INDIANA DEPARTMENT OF ENVIRONMENTAL MANAGEMENT
We make Indiana a cleaner, healthier place to live.

Frank O'Bannon
Governor

Lori F. Kaplan
Commissioner

100 North Senate Avenue
P. O. Box 6015
Indianapolis, Indiana 46206-6015
(317) 232-8603
(800) 451-6027
www.IN.gov/idem

April 29, 2003.

Mr. Paul E. Reynolds
Hoosier Energy - Lawrence County Station
P.O. Box 981
Bloomington, Indiana 47402-0908

Re: SPR 093-16653
First Significant Permit Revision to
MSOP 093-14495-00028

Dear Mr. Reynolds:

Hoosier Energy - Lawrence County Station was issued a minor source operating permit on March 6, 2002 for a peaking power generation source. A letter requesting a revision to this permit was received on October 11, 2002. Pursuant to the provisions of 326 IAC 2-6.1-6 a significant permit revision to this permit is hereby approved as described in the attached Technical Support Document.

The modification consists of the replacement of the existing four (4) combustion turbines with six (6) new combustion turbines which has resulted in a limited potential to emit of PM, PM_{10}, SO_2, VOC, CO and NO_X of less than 62.60, 50.34, 149.35, 52.54, 137.87, and 250 tons per year, respectively.

The following construction conditions are applicable to the proposed project:

1. The data and information supplied with the application shall be considered part of this permit revision approval. Prior to any proposed change in construction which may affect the potential to emit (PTE) of the proposed project, the change must be approved by the Office of Air Quality (OAQ).

2. This approval to construct does not relieve the permittee of the responsibility to comply with the provisions of the Indiana Environmental Management Law (IC 13-11 through 13-20; 13-22 through 13-25; and 13-30), the Air Pollution Control Law (IC 13-17) and the rules promulgated thereunder, as well as other applicable local, state, and federal requirements.

3. Pursuant to IC 13-15-5-3, this approval to construct becomes effective upon its issuance.

4. Pursuant to 326 IAC 2-1.1-9 (Revocation), the Commissioner may revoke this approval if construction is not commenced within eighteen (18) months after receipt of this approval or if construction is suspended for a continuous period of one (1) year or more.

5. All requirements and conditions of this construction approval shall remain in effect unless modified in a manner consistent with procedures established pursuant to 326 IAC 2.

Pursuant to 326 IAC 2-6.1-6, the minor source operating permit shall be revised by incorporating the significant permit revision into the permit. All other conditions of the permit shall remain unchanged and in effect. Please attach a copy of this permit revision which includes this letter, the attached operating conditions applicable to these emission units, and revised permit pages to the front of the original permit.

This decision is subject to the Indiana Administrative Orders and Procedures Act - IC 4-21.5-3-5. If you have any questions on this matter, please contact Michael S. Schaffer, c/o OAQ, 100 North Senate Avenue, P.O. Box 6015, Indianapolis, Indiana, 46206-6015, at 631-691-3395, ext. 15 or in Indiana at 1-800-451-6027 (ext 631-691-3395).

Sincerely,

Signed by
Paul Dubenetzky, Chief
Permits Branch
Office of Air Quality

Attachments
MSS:MES
cc: File - Lawrence County
U.S. EPA, Region V
Lawrence County Health Department
Air Compliance Section Inspector - Ray Schick
Compliance Branch - Karen Nowak
Administrative and Development - Lisa Lawrence
Technical Support and Modeling - Michele Boner

INDIANA DEPARTMENT OF ENVIRONMENTAL MANAGEMENT
We make Indiana a cleaner, healthier place to live.

Frank O'Bannon
Governor

Lori F. Kaplan
Commissioner

-+

100 North Senate Avenue
P. O. Box 6015
Indianapolis, Indiana 46206-6015
(317) 232-8603
(800) 451-6027
www.IN.gov/idem

NEW SOURCE CONSTRUCTION PERMIT

and MINOR SOURCE OPERATING PERMIT
OFFICE OF AIR QUALITY

Hoosier Energy - Lawrence County Station
1000 S. Old Palistine Road
Mitchell, Indiana 47446

(herein known as the Permittee) is hereby authorized to operate subject to the conditions contained herein, the emission units described in Section A (Source Summary) of this permit.

This permit is issued to the above mentioned company under the provisions of 326 IAC 2-1.1, 326 IAC 2-6.1 and 40 CFR 52.780, with conditions listed on the attached pages.

Operation Permit No.: MSOP 093-14495-00028	
Original signed by Paul Dubenetzky Issued by: Paul Dubenetzky, Branch Chief Office of Air Quality	Issuance Date: March 6, 2002 Expiration Date: March 6, 2007

First Significant Permit Revision 093-16653-00028	Changed Pages: 2 through 4, 18 through 24, 26, and 29 Pages Added: 23a Pages Deleted: 25
Issued by:Signed by Paul Dubenetzky, Branch Chief Office of Air Quality	Issuance Date: April 29, 2003

INDIANA DEPARTMENT OF ENVIRONMENTAL MANAGEMENT

We make Indiana a cleaner, healthier place to live.

Frank O'Bannon
Governor

Lori F. Kaplan
Commissioner

100 North Senate Avenue
P. O. Box 6015
Indianapolis, Indiana 46206-6015
(317) 232-8603
(800) 451-6027
www.IN.gov/idem

TABLE OF CONTENTS

SECTION A SOURCE SUMMARY

This permit is based on information requested by the Indiana Department of Environmental Management (IDEM), Office of Air Quality (OAQ). The information describing the source contained in Conditions A.1 and A.2 is descriptive information and does not constitute enforceable conditions. However, the Permittee should be aware that a physical change or a change in the method of operation that may render this descriptive information obsolete or inaccurate may trigger requirements for the Permittee to obtain additional permits or seek modification of this permit pursuant to 326 IAC 2, or change other applicable requirements presented in the permit application.

A.1 General Information [326 IAC 2-5.1-3(c)] [326 IAC 2-6.1-4(a)]

The Permittee owns and operates a stationary peaking power generating facility.

Authorized Individual:	Manager Generation Technical Services
Source Address:	1000 S. Old Palistine Road, Mitchell, Indiana 47446
Mailing Address:	P.O. Box 908, Bloomington, Indiana 47402-0908
Phone Number:	812-876-0261
SIC Code:	4911
County Location:	Lawrence
County Status:	Attainment for all criteria pollutants
Source Status:	Minor Source, under PSD; Minor Source, Section 112 of the Clean Air Act

A.2 Emissions units and Pollution Control Equipment Summary

This stationary source is approved to construct and operate the following emissions units and pollution control devices:

(a) Six (6) simple cycle, dual fuel turbine generator units combusting pipeline natural gas as a primary fuel and No. 2 fuel oil as a back-up fuel, identified as Turbines 1, 2, 3, 4, 5, and 6, each with a net generating capacity of 43.8 megawatts, and a corresponding heat input capacity of 384.44 million British thermal units per hour, each, equipped with water injection for NO_X control, and exhausting to Stacks 1, 2, 3, 4, 5, and 6, respectively.

(b) One (1) diesel fuel storage tank, identified as #1, with a maximum capacity of 1,200,000 gallons.

(c) One (1) emergency diesel fire pump, identified as pump 1, with a maximum capacity of 208 HP, and exhausts to Stack 7.

A.3 Part 70 Permit Applicability [326 IAC 2-7-2]

This stationary source is required to have a Part 70 permit by 326 IAC 2-7-2 (Applicability) because:

(a) It is a major source, as defined in 326 IAC 2-7-1(22);

(b) It is an affected source under Title IV (Acid Deposition Control) of the Clean Air Act, as defined in 326 IAC 2-7-1(3);

(c) It is a source in a source category designated by the United States Environmental Protection Agency (U.S. EPA) under 40 CFR 70.3 (Part 70 - Applicability).

A.4 Acid Rain Permit Applicability [40 CFR Part 72.30]

This stationary source shall be required to have a Phase II, Acid Rain permit by 40 CFR Part 72.30 (Applicability) because:

(a) The combustion turbines are new units under 40 CR Part 72.6.

(b) The source cannot operate the combustion units until its Phase II, Acid Rain permit has been issued.

SECTION D.1 EMISSIONS UNIT OPERATION CONDITIONS

Facility Description: Six (6) combustion turbines

(a) Six (6) simple cycle, dual fuel turbine generator units combusting pipeline natural gas as a primary fuel and No. 2 fuel oil as a back-up fuel, identified as Turbines 1, 2, 3, 4, 5, and 6, each with a net generating capacity of 43.8 megawatts, and a corresponding heat input capacity of 384.44 million British thermal units per hour, each, equipped with water injection for NO_X control, and exhausting to Stacks 1, 2, 3, 4, 5, and 6, respectively.

(b) One (1) diesel fuel storage tank, identified as #1, with a maximum capacity of 1,200,000 gallons.

(c) One (1) emergency diesel fire pump, identified as pump 1, with a maximum capacity of 208 HP, and exhausts to Stack 7.

(The information describing the process contained in this facility description box is descriptive information and does not constitute enforceable conditions.)

Emission Limitations and Standards

D.1.1 PSD Minor Limit [326 IAC 2-2]

(a) The pipeline natural gas usage from the six (6) turbines shall be limited to less than 4,760.5 million standard cubic feet per twelve (12) consecutive month period with compliance determined at the end of each month equivalent to the following:

(1) Less than 248.93 tons of NO_X per year including start-up and shutdown, based on:

(A) An NO_X emission rate of 0.1106 pounds per million British thermal units heat input when combusting natural gas, and

(B) An NO_X emission rate of 0.1893 pounds per million British thermal units heat input when combusting No. 2 fuel oil.

(2) Less than 123.00 tons of CO per year including start-up and shutdown, based on:

(A) A CO emission rate of 0.0546 pounds per million British thermal units heat input when combusting natural gas, and

(B) A CO emission rate of 0.0547 pounds per million British thermal units heat input when combustion No. 2 fuel oil.

(3) Less than 132.82 tons of SO_2 per year, based on:

(A) An SO_2 emission rate of 0.0006 pounds per million British thermal units heat input when combusting natural gas, and

(B) An SO_2 emission rate of 0.1010 pounds per million British thermal units heat input when combusting No. 2 fuel oil.

For purposes of determining compliance based on NO_X, 1,000 gallons of No. 2 fuel oil shall be equivalent to 0.2516 million standard cubic feet of natural gas.

(b) Compliance with these limits and limiting the operation of the emergency diesel fire pump to 500 hours per year makes 326 IAC 2-2 (Preventive of Significant Deterioration) not

applicable.

(c) The sulfur content of the fuel oil shall not exceed 0.05 percent by weight.

D.1.2 General Provisions Relating to NSPS [326 IAC 12-1] [40 CFR Part 60, Subpart A]

The provisions of 40 CFR Part 60, Subpart A - General Provisions, which are incorporated by reference in 326 IAC 12-1, apply to the facility described in this section except when otherwise specified in 40 CFR Part 60, Subpart GG.

D.1.3 40 CFR Part 60, Subpart GG Applicability (Stationary Gas Turbine)

(a) The six (6) combustion turbines are subject to 40 CFR Part 60, Subpart GG, because the heat input at peak load is equal to or greater than 10.7 gigajoules per hour, based on the lower heating value of the fuel fired.

(b) Pursuant to 326 IAC 12-1 and 40 CFR 60, Subpart GG (Stationary Gas Turbines), the Permittee shall:

(1) limit nitrogen oxides emissions, as required by 40 CFR 60.332, to:

$$STD = 0.0075 \frac{(14.4)}{Y} + F ,$$

where STD = allowable NO_X emissions (percent by volume at 15 percent oxygen on a dry basis).

Y = manufacturer's rated heat rate at manufacturer's rated load (kilojoules per watt hour) or, actual measured heat rate based on lower heating value of fuel as measured at actual peak load for the facility. The value of Y shall not exceed 14.4 kilojoules per watt hour.

F = NO_X emission allowance for fuel-bound nitrogen as defined in paragraph (a)(3) of 40 CFR 60.332.

(2) limit sulfur dioxide emissions, as required by 40 CFR 60.333, to 0.015 percent by volume at 15 percent oxygen on a dry basis, or use natural gas fuel with a sulfur content less than or equal to 0.8 percent by weight.

D.1.4 40 CFR Part 60, Subpart Kb Applicability (Volatile Organic Storage Vessels)

(a) The one (1) fuel oil storage tank is subject to 40 CFR Part 60, Subpart Kb because the maximum capacity is greater than 40 m^3 and is used to store volatile organic liquids (including petroleum) for which construction, reconstruction, or modification commenced after July 23, 1984.

(b) Pursuant to 40 CFR Part 60, Subpart Kb, the Permittee shall notify the Administrator and IDEM, OAQ, within 30 days when the maximum true vapor pressure of the liquid exceeds the respective maximum true vapor pressure values for each volume range. (Available data on the storage temperature may be used to determine the maximum vapor pressure as determined in 40 CFR Part 60.116b(e)(1)-(3)).

D.1.5 Sulfur Dioxide (SO_2)

Pursuant to 326 IAC 7-1.1-2 (SO_2 Emissions Limitations) the SO_2 emissions from the fuel combustion shall not exceed five tenths (0.5) pounds per MMBtu heat input.

D.1.6 Carbon Monoxide Emission Limitations [326 IAC 9-1]

This source is subject to 326 IAC 9-1 because it is a stationary source of CO emissions commencing operation after March 21, 1972. There are no applicable CO emission limits, under this state rule, established for this type of operation.

D.1.7 Preventive Maintenance Plan

A Preventive Maintenance Plan, in accordance with Section C - Preventive Maintenance Plan, of this permit, is required for these emission units and their control devices.

Compliance Determination Requirements

D.1.8 Testing Requirements [326 IAC 2-1.1-11] [40 CFR 75.12]

(a) The Permittee shall perform initial performance tests for Turbines 1, 2, 3, 4, 5, and 6, to measure NO_X emission rates at heat input rate levels corresponding to different load levels and plot the correlation between heat input rate and NO_X emission rate in order to determine the emission rate of the units. The testing shall be performed in accordance with Section 2.1 of Appendix E of 40 CFR 75.

(b) The Permittee shall retest the NO_X emission rate of each turbine prior to the earlier of 3,000 unit operating hours or the five (5) year anniversary and renewal of its operating permit under 40 CFR 72. This testing shall be performed in accordance with Section 2.1 of Appendix E of 40 CFR 75.

(c) Within sixty (60) days after achieving maximum production rate, but no later than one hundred and eighty (180) days after initial start-up, the Permittee shall conduct CO stack tests for two (2) of the six (6) turbines utilizing methods as approved by the Commissioner. These tests shall be repeated at least once every five (5) years from the date of this valid compliance demonstration. Testing shall be conducted in accordance with Section C-Performance Testing.

D.1.9 40 CFR Part 60, Subpart GG Compliance Requirements (Stationary Gas Turbines)

Pursuant to 40 CFR Part 60, Subpart GG (Stationary Gas Turbines), the Permittee shall monitor the nitrogen and sulfur content of the natural gas on a daily basis as follows:

(a) install a continuous monitoring system to monitor and record the fuel consumption and the ratio of water to fuel being fired in the turbine, as required by 40 CFR 60.334(a);

(b) determine compliance with the nitrogen oxides and sulfur dioxide standards in 40 CFR 60.332 and 60.333(a), per the requirements described in 40 CFR 60.335(c);

(c) determine the sulfur content of the natural gas being fired in the turbine by ASTM methods D 1072-80, D 3031-81, D 4084-82, or D 3246-81. The applicable ranges of some ASTM methods mentioned are not adequate to measure the levels of sulfur in some fuel gases. Dilution of samples before analysis (with verification of the dilution ratio) may be used, subject to the approval of the Administrator;

(d) determine the nitrogen content of the natural gas being fired in the turbine by using analytical methods and procedures that are accurate to within 5 percent and are approved by the Administrator; and

(e) report periods of excess emissions, as required by 40 CFR 334(c).

The analyses required above may be performed by the owner or operator, a service contractor retained by the owner or operator, the fuel vendor or any other qualified agency.

Owners, operators or fuel vendors may develop custom schedules for determination of the nitrogen and sulfur content based on the design and operation of the affected facility and the characteristics of the fuel supply. These custom schedules shall be substantiated with data and must be approved by the Administrator before they can be used to comply with the above requirements.

D.1.10 326 IAC 7-2 [Sulfur Content Compliance]

Pursuant to 326 IAC 7-2-1, the Permittee shall demonstrate that the fuel oil sulfur content does not exceed 0.5 pounds per million Btu (lb/MMBtu) by:

(a) Fuel sampling and analysis data shall be collected pursuant to procedures specified in 326 IAC 3-7-4 for oil combustion, and these data may be used to determine compliance or non-compliance with the emission limitations contained in 326 IAC 7-1.1. Computation of calculated sulfur dioxide emission rates from fuel sampling and analysis data shall be based on AP-42 emission factors, unless other emission factors based on site specific sulfur dioxide measurements are approved by the commissioner and the U.S. EPA. Fuel sampling and analysis data shall be collected as follows:

compliance or noncompliance shall be determined by using a calendar month average sulfur dioxide emission rate in pounds per million Btu unless a shorter averaging time or alternate methodology is specified under 326 IAC 7-2. Analyzing the oil sample to determine the sulfur content of the oil via the procedures in 40 CFR 60, Appendix A, Method 19.

(1) Oil samples may be collected from the fuel tank immediately after the fuel tank is filled and before any oil is combusted; and

(2) If a partially empty fuel tank is refilled, a new sample and analysis would be required upon filling.

(b) Compliance or noncompliance with the emission limitation specified in 326 IAC 7-1.1 may be determined by conducting a stack test for sulfur dioxide emissions from the six (6) combustion turbines, using 40 CFR 60, Appendix A, Method 6, 6A, 6C, or 8, in accordance with the procedures in 326 IAC 3-6.

(c) A determination of noncompliance pursuant to either of the methods specified in (a) or (b) above shall not be refuted by evidence of compliance pursuant to the other method.

D.1.11 Nitrogen Oxides Monitoring Requirement [326 IAC 10-4-4(b)(1)] [326 IAC 10-4-12(b) and (c)] [40 CFR 75]

The Permittee shall meet the monitoring requirements of 326 IAC 10-4-12(b)(1) through (b)(3) that are applicable to their monitoring systems for the NO_X budget units on or before the later of the dates listed in paragraphs (a) and (b). The Permittee shall record, report, and quality assure the data from the monitoring systems on and after the later of the following dates in accordance with 326 IAC 10-4-12 and 40 CFR 75:

(a) May 1, 2003.

(b) The earlier of:

(1) one hundred eighty (180) days after the date on which the first unit commences operation; or

(2) ninety (90) days after the date the first unit commences commercial operation.

D.1.12 NO_X Control

In order to comply with Conditions D.1.1(a)(1)(A), D.1.1(a)(1)(B) and D.1.3(b)(1), the water injection for NO_X control shall be operation and control emissions from each of the six (6) combustion turbines at all times that the combustion turbines are in operation.

Compliance Monitoring Requirements [326 IAC 2-5.1-3(e)(2)] [326 IAC 2-6.1-5(a)(2)]

D.1.13 Visible Emissions Notations

(a) Visible emission notations of the Turbines 1, 2, 3, 4, 5, and 6 stack exhausts shall be performed after four (4) hours of continuous operation once per shift during normal daylight operation when combusting No. 2 fuel oil. A trained employee shall record whether emissions are normal or abnormal.

(b) For processes operated continuously, "normal" means those conditions prevailing, or expected to prevail, eighty percent (80%) of the time the process is in operation, not counting startup or shut down time.

(c) In the case of batch or discontinuous operations, readings shall be taken during that part of the operation that would normally be expected to cause the greatest emissions.

(d) A trained employee is an employee who has worked at the plant at least one (1) month and has been trained in the appearance and characteristics of normal visible emissions for that specific process.

(e) The Compliance Response Plan for this unit shall contain troubleshooting contingency and response steps for when an abnormal emission is observed. Failure to take response steps in accordance with Section C - Compliance Response Plan - Preparation and Implementation shall be considered a violation of this permit.

D.1.14 Operation and Maintenance Plan

The Permittee shall prepare and maintain an Operation and Maintenance Plan for each combustion turbine. This plan shall insure that the six (6) combustion turbines are operated and maintained properly in accordance with manufacturer specifications and good air pollution control practices for minimizing emissions. The Operation and Maintenance Plan shall be kept onsite at all times.

D.1.15 NO_X Monitoring [40 CFR 75.12(d)]

(a) Pursuant to 40 CFR 72.9 and 40 CFR 75.12, the Permittee has elected to monitor NO_X emissions from the six (6) combustion turbines pursuant to 40 CFR 75, Appendix E, which is used for peaking units. Appendix E includes, but is not limited to, the following requirements:

(1) The Permittee shall perform initial performance tests for each turbine to measure NO_X emission rates at heat input rate levels corresponding to different load levels and plot the correlation between heat input rate and NO_X emission rate in order to determine the emission rate of the units. This testing shall be performed in accordance with Section 2.1 of Appendix E.

(2) The Permittee shall retest the NO_X emission rate for the turbines prior to the earlier of 3,000 unit operating hours or the five (5) year anniversary and renewal of its operating permit under 40 CFR Part 72.

(3) The Permittee shall record the time (hour and minute), load (megawatt), fuel flow rate and heat input rate (using the procedures in Section 2.1.3 of Appendix E) for each hour during which the unit combusts fuel. The Permittee shall calculate the total hourly heat input using equation E-1 of Appendix E and record the heat input rate for each fuel to the nearest 0.1 million British thermal units per hour. During partial unit operating hours, heat input must be represented as an hourly rate in million British thermal units per hour, as if the fuel were combusted for the entire hour at that rate in order to ensure proper correlation with the NO_X emission rate graph.

(4) The Permittee shall use the graph of the baseline correlation results to determine the NO_X emission rate (pounds per million British thermal units) corresponding to the heat input rate (million British thermal units per hour) and input this correlations into the data acquisition and handling system for the turbines. The data shall be linearly interpolation to 0.1 million British thermal units per hour heat input rate and 0.01 pounds per million British thermal units.

(b) If any combustion turbine exceeds a capacity factor of twenty percent (20%) in any given year, or exceeds an average capacity factor of ten percent (10%) for the previous three (3) years, then the Permittee shall install, certify, and operate an NO_X continuous emissions monitoring system (CEMS) by December 31 of the following calendar year on that turbine. The NO_X CEMS shall meet the minimum requirements of 40 CFR Part 75 and 326 IAC 3-5. If the required CEMS has not been installed and certified by that date, the Permittee shall report the maximum potential NO_X emission rate (MER) (as defined in 40 CFR 72.2) for each unit operating hour, starting with the first unit operating hour after the deadline and continuing until the CEMS has been provisionally certified.

Record Keeping and Reporting Requirements [326 IAC 2-1-3]

D.1.16 Record Keeping Requirements

(a) To document compliance with Conditions D.1.1 the Permittee shall maintain records of the following:

(1) amount of natural gas combusted (in million standard cubic feet) and No. 2 fuel oil (in gallons) per unit (turbine, heating equipment and fire pump engine) during each month;

(2) the percent sulfur content of the natural gas (if other than pipeline quality natural gas which is defined as natural gas that is provided by a supplier through a pipeline; 40 CFR Part 72.2) and No. 2 fuel oil of each unit (turbine and fire pump engine); and

(3) the Permittee shall maintain records required under 326 IAC 3-5-6 at the source in a manner so that they may be inspected by the IDEM, OAQ, or the U.S. EPA, if so requested or required.

(b) To document compliance with D.1.3, the source shall maintain records of the natural gas analyses, including the sulfur and nitrogen content of the gas, for a period of three (3) years.

(c) To document compliance with Condition D.1.4, the Permittee shall:

(1) maintain the records of the volatile organic liquid (VOL) stored;

(2) the period of storage;

(3) the maximum true vapor pressure of the volatile organic liquid (VOL) during the respective storage period; and

(4) shall keep readily accessible records showing the dimension of the storage vessel and an analysis showing the capacity of the storage vessel.

(d) To document compliance with Condition D.1.13, the Permittee shall maintain records of visible emission notations of the six (6) combustion turbines stack exhausts when combusting No. 2 fuel oil for four (4) continuous hours.

(e) To document compliance with Condition D.1.14, the Permittee shall keep records of the maintenance performed on each combustion turbine including the date and description of the

maintenance activities.

(f) To document compliance with Condition D.1.15, the Permittee shall record the time (hour and minute), load (megawatt), fuel flow rate and heat input (using the procedures in Section 2.1.3 of Appendix E) for each fuel to the nearest 0.1 million British thermal units per hour. During partial unit operating hours, heat input must be represented as an hourly rate in million British thermal units per hour, as if the fuel were combusted for the entire hour at that rate in order to ensure proper correlation to the NO_X emission rate graph.

(g) All records shall be maintained in accordance with Section C – General Record Keeping Requirements, of this permit.

D.1.17 Nitrogen Oxides Budget Trading Program [326 IAC 10-4-4(a)(1)] [326 IAC 10-4-9(e)(2)]

For NO_X budget units that will commence operation on or after May 1, 2000, the NO_X authorized account representative shall submit a request for NO_X allowances in accordance with 326 IAC 10-4-9(e) by September 1 of the calendar year that is one (1) year in advance of the first ozone control period for which the NO_X allowance allocation is requested. The NO_X authorized account representative shall submit a request each year that the units will require allowances from the new unit set aside until the units are allocated allowances from the existing source pool. These requests shall be submitted by the NO_X authorized account representative to:

Indiana Department of Environmental Management
Compliance Branch, Office of Air Quality
100 North Senate Avenue, P.O. Box 6015
Indianapolis, Indiana 46206-6015

D.1.18 Reporting Requirements

(a) A quarterly summary of the information to document compliance with Condition D.1.1 shall be submitted to the address listed in Section C - General Reporting Requirements, of this permit, using the reporting forms located at the end of this permit, or their equivalent, within thirty (30) days after the end of the quarter being reported.

(b) The Permittee shall report periods of excess emissions, as required by 40 CFR 60.334(c).

(c) The Permittee shall submit reports of calendar month average sulfur content, heat content, fuel consumption, and sulfur dioxide emission rate in pounds per million Btu upon request based on fuel sampling and analysis data in accordance with procedures specified under 326 IAC 3-7-4 to document compliance with Condition D.1.10.

(d) These reports shall be submitted within thirty (30) calendar days following the end of each calendar quarter and shall be in accordance with Section C – General Reporting Requirements of this permit.

INDIANA DEPARTMENT OF ENVIRONMENTAL MANAGEMENT
OFFICE OF AIR QUALITY
COMPLIANCE DATA SECTION

Part 70 Quarterly Report

Source Name: Hoosier Energy - Lawrence County Station
Source Address: 1000 S. Old Palistine Road, Mitchell, Indiana 47446
Mailing Address: P.O. Box 908, Bloomington, Indiana 47402-0908
Permit No.: MSOP 093-14495-00028
Facilities: Six (6) Combustion Turbines
Parameter: Fuel Usage
Limit: Less than a total of 4,760.5 million standard cubic feet of natural gas per twelve (12) consecutive month period with compliance determined at the end of each month where 1000 gallons of No. 2 fuel oil shall be equivalent to 0.2516 million standard cubic feet of natural gas equivalent to less than 248.93 tons of NO_X per year, less than 123.00 tons of CO per year, and less than 132.82 tons of SO_2 per year.

YEAR: _____

Month	Fuel Usage This Month	Fuel Usage Previous 11 Months	Fuel Usage 12 Month Total
	Natural Gas (mmscf) Including Equivalent No. 2 Fuel Oil	Natural Gas (mmscf) Including Equivalent No. 2 Fuel Oil	Natural Gas (mmscf) Including Equivalent No. 2 Fuel Oil

9 No deviation occurred in this month.

9 Deviation/s occurred in this month.

Deviation has been reported on: _____

Submitted by: _____

Title/Position: _____

Signature: _____

Date: _____

Phone: _____

Attach a signed certification to complete this report.

This page has been intentionally left blank.

INDIANA DEPARTMENT OF ENVIRONMENTAL MANAGEMENT
OFFICE OF AIR QUALITY
COMPLIANCE DATA SECTION

MINOR SOURCE OPERATING PERMIT
ANNUAL NOTIFICATION

This form should be used to comply with the notification requirements under 326 IAC 2-6.1-5(a)(5).

Company Name:	**Hoosier Energy - Lawrence County Station**
Address:	**1000 S. Old Palistine Road**
City:	**Mitchell, Indiana 47446**
Phone #:	**(812) 876-2021**
MSOP #:	**093-14495-00028**

I hereby certify that Hoosier Energy - Lawrence County Station is
- **9** still in operation.
- **9** no longer in operation.

I hereby certify that Hoosier Energy - Lawrence County Station is
- **9** in compliance with the requirements of MSOP 093-14495-00028
- **9** not in compliance with the requirements of MSOP 093-14495-00028

Authorized Individual (typed):
Title:
Signature:
Date:

If there are any conditions or requirements for which the source is not in compliance, provide a narrative description of how the source did or will achieve compliance and the date compliance was, or will be achieved.

Noncompliance:

Mail to: Permit Administration & Development Section
Office Of Air Management
100 North Senate Avenue
P. O. Box 6015
Indianapolis, Indiana 46206-6015

Hoosier Energy - Lawrence County Station
P.O. Box 908
Bloomington, Indiana 47402-0908

Affidavit of Construction

I, _____, being duly sworn upon my oath, depose and say:
(Name of the Authorized Representative)

1. I live in _____ County, Indiana and being of sound mind and over twenty-one (21) years of age, I am competent to give this affidavit.

2. I hold the position of _____ for _____.
(Title) (Company Name)

3. By virtue of my position with _____,I have personal
(Company Name)
knowledge of the representations contained in this affidavit and am authorized to make these representations on behalf of _____ .
(Company Name)

4. I hereby certify that Hoosier Energy - Lawrence County Station, 1000 S. Old Palistine Road, Mitchell, Indiana 47446, completed construction of six (6) combustion turbines at the stationary peaking power generating facility on _____in conformity with the requirements and intent of the construction permit application received by the Office of Air Quality on June 25, 2001 and as permitted pursuant to **Significant Permit Revision No. 093-16653, Plant ID No. 093-00028** issued on _____

5. I hereby certify that Hoosier Energy - Lawrence County Station is now subject to the Title V program and will submit a Title V (or FESOP) operating permit application within twelve (12) months from the postmarked submission date of this Affidavit of Construction.

Further Affiant said not.

I affirm under penalties of perjury that the representations contained in this affidavit are true, to the best of my information and belief.

_____
Signature

_____
Date

STATE OF INDIANA)
)SS
COUNTY OF _____)

Subscribed and sworn to me, a notary public in and for _____ County and State of Indiana on this _____ day of _____, 20 _____ .

My Commission expires: _____

_____
Signature

_____
Name (typed or printed)

Indiana Department of Environmental Management
Office of Air Quality

Addendum to the
Technical Support Document for a Permit Revision to a Minor Source Operating Permit

Source Name:	**Hoosier Energy - Lawrence County Station**
Source Location:	**1000 S. Palistine Road, Mitchell, Indiana 47446**
County:	**Lawrence**
SIC Code:	**4911**
Operating Permit No.:	**MSOP 093-14495-00028**
Operation Permit Issuance Date:	**March 6, 2002**
Significant Permit Revision No.:	**SPR 093-16653-00028**
Permit Reviewer:	**Michael S. Schaffer**

On February 5, 2003, the Office of Air Quality (OAQ) had a notice published in the Times - Mail in Bedford, Bedford, Indiana, stating that Hoosier Energy - Lawrence County Station had applied for a significant permit revision to their Minor Source Operating Permit, to substitute the four (4) permitted, but never constructed, combustion turbines with the construction and operation of six (6) different combustion turbines. The notice also stated that OAQ proposed to issue a permit revision for this construction and operation and provided information on how the public could review the proposed permit and other documentation. Finally, the notice informed interested parties that there was a period of thirty (30) days to provide comments on whether or not this permit should be issued as proposed.

On February 28, 2003, Darrell Bayless of Hoosier Energy submitted comments on the proposed permit revision. The summary of the comments and corresponding responses are as follows: The permit language, if changed, has deleted language as ~~strikeouts~~ and new language **bolded.**

Comment 1:

Change Condition A.1 from (812) 876-0341 to (812) 876-0261.

Response 1:

The phone number in Condition A.1 has been changed as follows:

Phone Number: 812-876-~~0341~~ **0261**

Comment 2:

In Condition D.1.12(a), Hoosier Energy is requesting the condition be changed to the following:

Visible emission notations of the Turbines 1, 2, 3, 4, 5, and 6 stack exhausts shall be performed once per shift when combusting No. 2 fuel oil and after four hours of continuous daylight operation.

The request to add the phrase “and after four hours of continuous operation” is requested since the site may be an unmanned site which would require personnel to mobilize to the site to make the observations.

If no personnel are on site and the facility begins to combust fuel oil then assurance of proper operation will be detected by the generator output of each machine or other alarms. Should the output be less than the expected value or a high level alarm condition exists then the machine(s) will be shutdown. Once the machine is shutdown from an alarm condition it will be visually and mechanically checked for problems prior to operating. Depending upon the problem the machine(s) will be subject to further maintenance or returned to service.

Response 2:

Although Hoosier Energy asked for visible emissions notations on stack exhausts once per shift and after four (4) hours of continuous operation on No. 2 fuel oil, upon discussion with Hoosier Energy, it has been clarified that their comment was intended to address replacing visible emissions notations on stack exhausts once per shift with four (4) hours of continuous operation. Therefore, as a result of the intent of this comment and additional information received on March 3, 2003, IDEM, OAQ will require that Hoosier Energy observe visible emissions after four (4) hours of continuous operation once per shift because the source is generally an unmanned source. The source will be manned if fuel oil is continuously combusted for a period of four (4) hours or more. Furthermore, to insure that the combustion turbines at this unmanned source are operating properly, an operation and maintenance plan and the record keeping of the maintenance activities for each combustion turbine that take place will be required. Condition D.1.12(a) (now Condition D.1.13(a)) has been revised and Conditions D.1.14 and D.1.16(d),(e) have been added as follows:

D.1.~~12~~ **13** Visible Emissions Notations

(a) Visible emission notations of the Turbines 1, 2, 3, 4, 5, and 6 stack exhausts shall be performed **after four (4) hours of continuous operation** once per shift during normal daylight operation when combusting No. 2 fuel oil. A trained employee shall record whether emissions are normal or abnormal.

D.1.14 Operation and Maintenance Plan

The Permittee shall prepare and maintain an Operation and Maintenance Plan for each combustion turbine. This plan shall insure that the six (6) combustion turbines are operated and maintained properly in accordance with manufacturer specifications and good air pollution control practices for minimizing emissions. The Operation and Maintenance Plan shall be kept onsite at all times.

D.1.~~14~~ **16** Record Keeping Requirements

(d) To document compliance with Condition D.1.13, the Permittee shall maintain records of visible emission notations of the six (6) combustion turbines stack exhausts when combusting No. 2 fuel oil for four (4) continuous hours.

(e) To document compliance with Condition D.1.14, the Permittee shall keep records of the maintenance performed on each combustion turbine including the date and description of the maintenance activities.

~~(d)~~**(f)** To document compliance with Condition D.1.~~13~~ **15**, the Permittee shall record the time (hour and minute), load (megawatt), fuel flow rate and heat input (using the procedures in Section 2.1.3 of Appendix E) for each fuel to the nearest 0.1 million British thermal units per hour. During partial unit operating hours, heat input must be represented as an hourly rate in million British thermal units per hour, as if the fuel were combusted for the entire hour at that rate in order to ensure proper correlation to the NO_X emission rate graph.

~~(e)~~**(g)** All records shall be maintained in accordance with Section C – General Record Keeping Requirements, of this permit.

On March 3, 2003, Stephen Loeschner representing the public, submitted comments on the proposed permit revision. The summary of the comments and corresponding responses are as follows: The permit language, if changed, has deleted language as ~~strikeouts~~ and new language **bolded.**

Comment 1:

The following is a comment on the draft construction and operation permit modification for Hoosier Energy in Lawrence County, Indiana ("Hoosier") described in Indiana Department of Environmental Management ("DEM") draft permit document package 093-16653-00028 ("16653") for essentially an abandonment of 093-14495-00028 ("14495") and a replacement with 16653.

Hoosier desires to avoid the law (regulation, rule) and evade the social responsibility regarding the use of Continuous Emission Monitoring Systems ("CEMS") for mixed oxides of nitrogen, expressed as a nitrogen dioxide equivalent ("NOx") by having its newly reconstructed campus of six 384.44 million Btu per hour gas and oil fired turbines considered as 40 CFR 72.2 "peaking units" and through that, feels entitled to a non-CEMS 40 CFR 75 Appendix E benefit.

40 CFR 72.2 "unit" clearly means reconstructed Hoosier would be six units, not one unit. Thus the 20% per year and 10% average over 3-year caps should apply to each unit. Thus, absent carbon monoxide ("CO") & NOx CEMS, there should be permit conditions that limit each unit to no more than 1,572 operating hours in any continuous 12-month period and no more than 2,628 operating hours in any continuous 36-month period (and provide that exceedances are violations for which penalties may be applied).

This should also be applied as fuel limits such that no unit may receive more than 661 million standard cubic of gas ("scf") in any continuous 12-month period and may not receive more than 991 million scf of gas in any continuous 36-month period (and provide that exceedances are violations for which penalties may be applied)...

Further, the federal clean air act, 42 USC 7401 et seq., was always meant to allow states to require superior permit terms to federal minimums. 326 IAC 2-1.1-11 provides, "The commissioner may require. [continuous emission] monitoring ... at any time to assure compliance with all applicable requirements.... This section applies to all sources issued a ... permit ... under this article." There should be no gift to Hoosier by not requiring NOx CEMS on all 6 individual stacks.

Response 1:

Although the preceding comment presents an argument in favor of requiring Hoosier Energy to install CEMS for NO_X and CO at the six (6) combustion turbine stacks, 40 CFR 75 Appendix E does provide an alterative use to CEMS for peaking units. 40 CFR 75 Appendix E does not contain any parameters within its requirements that insures that major PSD thresholds will not be exceeded by this source. Due to the uncertainty of vendor guaranteed emission rates, a fuel usage limit on the six (6) combustion turbines by itself does not insure that the major PSD thresholds will not be exceeded. Pursuant to 326 IAC 2-1.1-11, IDEM, OAQ, still has the authority to require Hoosier Energy to install CEMS for NO_X and CO to document compliance with the PSD minor limit.

The requirements of 40 CFR 72, 40 CFR 75, and 326 IAC 2-2 are evaluated separately in terms of applicability and compliance. Compliance with the requirements 40 CFR 72 and 40 CFR 75 does not necessarily demonstrate compliance with a PSD minor limit. 40 CFR 72 and 40 CFR 75 allow peaking units to use an alternative to CEMS. At this time, IDEM, OAQ, will not require the use of CEMS unless compliance with the PSD minor limit can not be demonstrated without the use of CEMS. To show compliance IDEM, OAQ has set a fuel usage limit, based on a more conservative emission factor than the vendor guarantee supplied by Hoosier Energy for NO_X, which will be verified by a stack test.

The following discussion substantiates that the alternative methodology to CEMS will assure that the PSD minor limit will not be exceeded.

First and foremost, IDEM, OAQ has reviewed the manufacturer's specifications of General Electric's (GE's) LM6000 Sprint, simple cycle combustion turbine (the type of turbines that will be used at this proposed source). The LM6000 Sprint combustion turbine uses water injection as a method to control NO_X emissions and increase power output, which is necessary during the peaking generation season. As the ambient air temperature increases, more water is injected into the combustion turbine which subsequently, decreases the NO_X emission rate and increases the power output of the turbine. Water injection becomes less effective with colder air temperatures, and therefore, the emission rates of NO_X increase. Since the six (6) combustion turbines can be used during any time of the year, not just the summer, IDEM, OAQ determined that the proposed fuel usage limit needs to be changed because it does not definitively show compliance with the PSD minor limit without the use of CEMS.

IDEM OAQ's rational for revising the proposed fuel usage limit from 5,324 mscf to 4,760.5 mscf, is detailed below:

Upon IDEM, OAQ's requests, Hoosier Energy provided detailed information on March 18 and April 1, 2003 regarding vendor guaranteed emission rates for GE's LM6000 Sprint, simple cycle combustion turbine. Performance tests conducted on the same model combustion turbine in Indiana were provided to support and confirm that the information provided by Hoosier Energy is accurate.

On September 26 and 27, 2000, Worthington Generation Peaking Station (Plt ID 055-00034) in Bloomfield, Indiana conducted performance tests on Units 1 - 4 which are GE LM6000 Sprint units. The highest NO_X emission rate recorded in any one (1) performance test on those units was 38.8 pounds of NO_X per hour between 9:15 and 10:15 AM on September 26. The temperatures ranged from 48 to 54 degrees Fahrenheit during the test based on the temperatures at the Monroe County Airport in Bloomington, Indiana. The vendor guaranteed emission rate between 30 and 60 degrees Fahrenheit is either 41 or 42 pounds of NO_X per hour. Thus, the Worthington Generation Peaking Station operated well within the vendor guaranteed emission rates for NO_X.

There are many atmospheric conditions that can affect the NO_X emission rates from a combustion turbine (air temperature, atmospheric pressure, relative humidity, etc.). Based on the information provided by Hoosier Energy, on April 1, 2003, the atmospheric condition that affects NO_X emissions from combustion turbines the most is fluctuations in air temperature. The estimated vendor guaranteed NO_X emission rates for the GE LM6000 Sprint simple cycle combustion turbine at specific air temperatures are listed in the following table:

Air Temperature (degrees Fahrenheit)	**Estimated Vendor Guaranteed NO_X Emission Rate (lbs/hr)/Turbine**
91	38
90	37
60	41
30	42
0	42

IDEM, OAQ, has plotted the above GE data. The vendor guarantee shows that there is an inverse relationship between air temperature and NO_X emission rates. In addition, IDEM, OAQ extrapolated this data to the annual average minimum temperature for Lawrence County, Indiana, which is -5 to -10 degrees Fahrenheit.

The extrapolated NO_X emission rate for the GE LM6000 Sprint simple cycle combustion turbine is 42.5 pounds per hour at -10 degrees Fahrenheit. IDEM, OAQ has used this ultra-conservative NO_X emission rate of 42.5 pounds per hour rather than 38.0 pounds per hour to determine the natural gas fuel usage limit (See Pages 1 through 6 of 6 in Appendix A of this document for detailed emissions calculations) to render requirements of 326 IAC 2-2 not applicable. Therefore, the fuel usage limit calculated with the ultra-conservative 42.5 pounds of NO_X per hour emission factor will insure compliance with the PSD minor limit without the use of CEMS. To further insure compliance with the PSD minor limit, Hoosier Energy will be required to operate the water injection for NO_X control at all times that the combustion turbines are in operation. This compliance determination requirement has been added to the proposed revision because the six (6) combustion turbines can operate without the use of water injection.

Secondly, this revision is not defined as a reconstruction because the combustion turbines permitted by MSOP 093-14495-00028, issued on March 6, 2002 were never constructed, installed and/or operated. Hoosier Energy - Lawrence County Station will be generally an unmanned peaking power generating source and has provided a methodology for an alternative to CEMS pursuant to 40 CFR 75 Appendix E for its peaking units.

Each of the proposed combustion turbines meets the definition of “unit” pursuant to 40 CFR 72.2 and the requirements of 40 CFR 75.12(d) applies to each combustion turbine. Condition D.1.15(b) (formerly Condition D.1.13(b)) of the proposed permit revision states:

“If any combustion turbine exceeds a capacity factor of twenty percent (20%) in any given year, or exceeds an average capacity factor of ten percent (10%) for the previous three (3) years, then the Permittee shall install, certify, and operate an NO_X continuous emissions monitoring system (CEMS) by December 31 of the following calendar year on that turbine.”

Pursuant to 40 CFR 72.2 capacity factor is defined as:

(a) The ratio of a unit’s actual annual electric output (expressed in MWe-hr) to the unit’s name-plate capacity multiplied by 8,760 hours, or

(b) The ratio of a unit’s annual heat input (in million British thermal units or equivalent units of measure) to the units maximum design heat input (in million British thermal units or equivalent units of measure) multiplied by 8,760 hours.

Note that the capacity factor for each unit is calculated based on 8,760 hours pursuant to 40 CFR 72.2. If a combustion turbine operates at or less than the percentage capacity factors, a limit on the number of hours of operation or a fuel limit based on the number of hours of operation for the combustion turbines does not need to be imposed.

NO_X and CO emissions at a 20% capacity factor in any given year and a 10% previous three (3) year average capacity factor (which defines the units as peaking units pursuant to 40 CFR 72 and 75) can be determined as follows:

NO_X Emissions = ((20% capacity factor x 8,760 hours/year x 6 combustion turbines) x (a conservative emission rate of 42.5 pounds of NO_X/hour)) / (2000 pounds/1 ton) = 223.4 tons/year

CO Emissions = ((20% capacity factor x 8,760 hours/year x 6 combustion turbines) x (a conservative emission rate of 21.0 pounds of CO/hour)) / (2000 pounds/1 ton) = 110.4 tons/year

NO_X and CO emissions at a 10% average capacity factor (which also defines the units as peaking units pursuant to 40 CFR 72 and 75) can be determined as follows:

NO_X Emissions = ((10% average capacity factor x 8,760 hours/year x 6 combustion turbines) x (a conservative emission rate of 42.5 pounds of NO_X/hour)) / (2000 pounds/1 ton) = 111.7 tons/year average

CO Emissions = ((10% average capacity factor x 8,760 hours/year x 6 combustion turbines) x (a conservative emission rate of 21.0 pounds of CO/hour)) / (2000 pounds/1 ton) = 55.2 tons/year average

In order for the units at this source to remain "peaking units", the NO_X and CO emissions at this source can not exceed an average of 111.7 and 55.2 tons per year, respectively, over a three (3) year period. Therefore, the peaking unit definition (20% capacity factor in any given year and a 10% average capacity factor over three (3) years) assures that Hoosier Energy will be required to install CEMS before their actual annual NO_X emissions approach the major PSD thresholds of 250 tons of NO_X and CO per year.

In conclusion, IDEM, OAQ, has determined that the stricter fuel usage limit calculated with the ultra-conservative 42.5 pounds of NO_X per hour emission rate, verified by a stack test, in combination with the limitations imposed by the definition of a peaking power generation source is a sufficient alternative methodology to CEMS. Furthermore, the alternative methodology to CEMS in Condition D.1.15(a)(3) and (4) (formally Condition D.1.13(a)(3) and (4)) is consistent with requirements of 40 CFR 72 and 40 CFR 75, for peaking power generation sources.

Therefore, Condition D.1.1 and the respective quarterly report form have been changed and Condition D.1.12 has been added as follows:

D.1.1 PSD Minor Limit [326 IAC 2-2] ~~[40 CFR 52.21]~~

(a) The pipeline natural gas usage from the six (6) turbines shall be limited to less than ~~5,324~~ **4,760.5** million standard cubic feet per twelve (12) consecutive month period with compliance determined at the end of each month equivalent to the following:

(1) Less than 248.93 tons of NO_X per year including start-up and shutdown, based on:

(A) An NO_X emission rate of ~~0.0988~~ **0.1106** pounds per million British thermal units heat input when combusting natural gas, and

(B) An NO_X emission rate of ~~0.1693~~ **0.1893** pounds per million British thermal units heat input when combusting No. 2 fuel oil.

(2) Less than ~~137.57~~ **123.00** tons of CO per year including start-up and shutdown, based on:

(A) A CO emission rate of 0.0546 pounds per million British thermal units heat input when combusting natural gas, and

(B) A CO emission rate of 0.0547 pounds per million British thermal units heat input when combustion No. 2 fuel oil.

(3) Less than ~~148.55~~ **132.82** tons of SO_2 per year, based on:

(A) An SO_2 emission rate of 0.0006 pounds per million British thermal units heat input when combusting natural gas, and

(B) An SO_2 emission rate of 0.1010 pounds per million British thermal units heat input when combusting No. 2 fuel oil.

For purposes of determining compliance based on NO_X, 1,000 gallons of No. 2 fuel oil shall be equivalent to 0.2516 million standard cubic feet of natural gas.

(b) Compliance with these limits and limiting the operation of the emergency diesel fire pump to 500 hours per year makes 326 IAC 2-2 (Preventive of Significant Deterioration) ~~and 40 CFR 52.21~~ not applicable.

D.1.12 NO_X Control

In order to comply with Conditions D.1.1(a)(1)(A), D.1.1(a)(1)(B) and D.1.3(b)(1), the water injection for NO_X control shall be operation and control emissions from each of the six (6) combustion turbines at all times that the combustion turbines are in operation.

INDIANA DEPARTMENT OF ENVIRONMENTAL MANAGEMENT
OFFICE OF AIR QUALITY
COMPLIANCE DATA SECTION

Part 70 Quarterly Report

Source Name:	Hoosier Energy - Lawrence County Station
Source Address:	1000 S. Old Palistine Road, Mitchell, Indiana 47446
Mailing Address:	P.O. Box 908, Bloomington, Indiana 47402-0908
Permit No.:	MSOP 093-14495-00028
Facilities:	Six (6) Combustion Turbines
Parameter:	Fuel Usage
Limit:	Less than a total of ~~5,324~~ **4,760.5** million standard cubic feet of natural gas per twelve (12) consecutive month period with compliance determined at the end of each month where 1000 gallons of No. 2 fuel oil shall be equivalent to 0.2516 million standard cubic feet of natural gas equivalent to less than 248.93 tons of NO_X per year, less than ~~137.57~~ **123.00** tons of CO per year, and less than ~~148.55~~ **132.82** tons of SO_2 per year.

Comment 2:

Allowing a total of 5,324 million scf gas with 16653 Condition D.1.1(a) and having "may close the barn door more than a year after the horse is gone" 16653 Condition D.1.13(b) language does not assure that the 250 tpy NOx cap is not violated.

Response 2:

The record keeping required by Condition D.1.17 (formerly Condition D.1.15) and the quarterly reporting required by Condition D.1.18 (formerly Condition D.1.16), ensures that the source is complying with the revised proposed fuel usage limit in Condition D.1.1. Furthermore, Condition D.1.8 requires testing to certify that the source will be in compliance with the NO_X emission factors specified in Condition D.1.1(a)(1)(A) and (B). The combination of the natural gas usage limit and the specified NO_X emission factors will insure that NO_X emissions are less than two hundred fifty (250) tons per year. Therefore, no additional changes have been made to the proposed permit.

Comment 3:

There is zero protection from CO violations of 250 tpy as there is zero testing to see what the units do. A vendor guarantee is nothing. As response to comment provide all knowledge of non-vehicle vendors fined for CAA violations after it was found that their products' emission rates exceeded the guaranteed rate. Hoosier may or may not have an enforceable contract, and it may or may not choose to enforce its contract. There is no contract between DEM and the "vendor." There should be no gift to Hoosier by not requiring CO CEMS on all individual stacks.

As response to comment, publish the unabridged vendor guarantee.

And describe with particularity, how, with no CO test, DEM proposed to assure that Hoosier's CO emission would be 40 CFR 52.21(b)(17) federally enforceable as a practical matter at less than 250 tpy.

Response 3:

The revised proposed fuel usage limitation in Condition D.1.1 combined with the AP-42 emission factor for CO shows that CO emissions are 199.9 tons per year (less than two hundred fifty (250) tons per year). The CO emissions based on the AP-42 emission factor were calculated as follows:

4,760.5 mmcf /year x 84.0 pounds/mmcf / 2000 pounds/ton = 199.9 tons/year

The revised fuel usage limitation in Condition D.1.1 calculated with the ultra-conservative NO_X emission factor is the limiting case, compared to the other pollutants, and therefore, if the source is in compliance with the revised proposed fuel usage limitation, CO emissions will be less than two hundred fifty (250) tons per year. IDEM, OAQ will require a stack test on CO emissions for two (2) of the six (6) combustion turbines because the vendor guaranteed emission rates are uncertain, the limit on CO emissions in Condition D.1.1(a)(2) is greater than the Part 70 source threshold, and Hoosier Energy requested a CO CEMS exemption for their peaking units. Therefore, Condition D.1.8(c) has been added as follows:

D.1.8 Testing Requirements [326 IAC 2-1.1-11] [40 CFR 75.12]

(c) Within sixty (60) days after achieving maximum production rate, but no later than one hundred and eighty (180) days after initial start-up, the Permittee shall conduct CO stack tests for two (2) of the six (6) turbines utilizing methods as approved by the Commissioner. These tests shall be repeated at least once every five (5) years from the date of this valid compliance demonstration. Testing shall be conducted in accordance with Section C- Performance Testing.

Indiana Department of Environmental Management
Office of Air Quality

Technical Support Document (TSD) for a Permit Revision to a Minor Source Operating Permit

Source Background and Description

Source Name:	**Hoosier Energy - Lawrence County Station**
Source Location:	**1000 S. Old Palistine Road, Mitchell, Indiana 47446**
County:	**Lawrence**
SIC Code:	**4911**
Operation Permit No.:	**MSOP 093-14495-00028**
Operation Permit Issuance Date:	**March 6, 2002**
Significant Permit Revision No.:	**SPR 093-16653-00028**
Permit Reviewer:	**Michael S. Schaffer**

The Office of Air Quality (OAQ) has reviewed a revision application from Hoosier Energy relating to the construction and operation of the following emission units and pollution control devices:

Six (6) simple cycle, dual fuel turbine generator units combusting pipeline natural gas as a primary fuel and No. 2 fuel oil as a back-up fuel, identified as Turbines 1, 2, 3, 4, 5, and 6, each with a net generating capacity of 43.8 megawatts, and a corresponding heat input capacity of 384.44 million British thermal units per hour, each, equipped with water injection for NO_X control, and exhausting to Stacks 1, 2, 3, 4, 5, and 6, respectively.

History

On October 11, 2002, Hoosier Energy - Lawrence County Station submitted an application to IDEM, OAQ requesting permission to replace the four (4) existing combustion turbines (Turbines 1 - 4) with six (6) new combustion turbines (Turbines 1 -6). Hoosier Energy - Lawrence County Station was issued a Minor Source Operating Permit MSOP 093-14495-00028 on March 6, 2002.

In addition, Hoosier Energy - Lawrence County Station has requested that the existing NO_X and CO emission limitations in Condition D.1.1 of MSOP 093-14495-00028, issued on March 6, 2002, be replaced with a fuel usage limitation. Subsequently, the source has also requested that Condition D.1.10 of MSOP 093-14495-00028, issued on March 6, 2002, which requires a continuous emission monitoring system (CEMS) for NO_X and CO, be removed and replaced with a CEMS alternative use requirement for peaking power generation facilities as stated in Appendix E of 40 CFR 75.

Furthermore, Hoosier Energy Lawrence County Station has changed its location from 3.5 Miles SE of Bedford Northwest Quarter of Section 7, Bedford, Indiana to 1000 S. Old Palistine Road, Mitchell, Indiana 47446.

Enforcement Issue

There are no enforcement actions pending.

Stack Summary

Stack ID	Operation	Height (feet)	Diameter (feet)	Flow Rate (acfm)	Temperature (EF)
1	Turbine 1	45.0	9.00	561,000	841
2	Turbine 2	45.0	9.00	561,000	841
3	Turbine 3	45.0	9.00	561,000	841
4	Turbine 4	45.0	9.00	561,000	841
5	Turbine 5	45.0	9.00	561,000	841
6	Turbine 6	45.0	9.00	561,000	841

Recommendation

The staff recommends to the Commissioner that the MSOP Significant Permit Revision be approved. This recommendation is based on the following facts and conditions:

Unless otherwise stated, information used in this review was derived from the application and additional information submitted by the applicant.

An application for the purposes of this review was received on October 11, 2002.

Emission Calculations

The calculations submitted by the applicant have been verified and found to be accurate and correct. These calculations are provided in Pages 1 through 6 of 6 of Appendix A of this document.

Potential To Emit of Revision

Pursuant to 326 IAC 2-1.1-1(16), Potential to Emit is defined as "the maximum capacity of a stationary source to emit any air pollutant under its physical and operational design. Any physical or operational limitation on the capacity of a source to emit an air pollutant, including air pollution control equipment and restrictions on hours of operation or type or amount of material combusted, stored, or processed shall be treated as part of its design if the limitation is enforceable by the U.S. EPA."

This table reflects the PTE before controls for this revision. Control equipment is not considered federally enforceable until it has been required in a federally enforceable permit.

Pollutant	Potential To Emit (tons/year)
PM	147.33
PM_{10}	142.92
SO_2	667.59
VOC	154.71
CO	662.18
NO_X	2,089.00

Note that the PTE of the revision is based on 64.1% of the PTE as stated on Page 2 of 12 of the Addendum to the TSD for MSOP 093-14495-00028, issued on March 6, 2002 less fuel pump and unpaved roads emissions. The calculation is as follows:

Original PTE of the Pollutant - PTE of the Fuel Pump and Unpaved Roads x (total nameplate capacity of the revision / total nameplate capacity of the four (4) existing turbines before the revision) = PTE of Turbines for Pollutant

Or

$(PTE_{Original} - PTE_{fuel\ pump/unpaved\ roads})$ x (44 megawatts x 6 turbines / 103 megawatts x 4 turbines) = $PTE_{Turbines}$

$(PTE_{Original} - PTE_{fuel\ pump/unpaved\ roads})$ x (264 megawatts / 412 megawatts) = $PTE_{Turbines}$

Similarly for HAPs:

HAPs	Potential To Emit (tons/year)
Formaldehyde	2.43
Others	1.28
TOTAL	3.71

Justification for Revision

The MSOP is being revised through a MSOP Significant Permit Revision. This revision is being performed pursuant to 326 IAC 2-6.1-6(i). Pursuant to 326 IAC 2-6.1-6(i)(1)(E), any modification with the potential to emit of greater than or equal to twenty-five (25) tons per year of PM, PM_{10}, SO_2, NO_X, or VOC and is not subject to the requirements of 326 IAC 2-6.1-6(d) or (g), shall be considered a significant permit revision.

County Attainment Status

The source is located in Lawrence County.

Pollutant	Status
PM_{10}	attainment
SO_2	attainment
NO_2	attainment
Ozone	attainment
CO	attainment
Lead	attainment

(a) Volatile organic compounds (VOC) are precursors for the formation of ozone. Therefore, VOC emissions are considered when evaluating the rule applicability relating to the ozone standards. Lawrence County has been designated as attainment or unclassifiable for ozone. Therefore, VOC emissions were reviewed pursuant to the requirements for Preven-

tion of Significant Deterioration (PSD), 326 IAC 2-2 and 40 CFR 52.21.

(b) Lawrence County has been classified as attainment or unclassifiable for all remaining criteria pollutants. Therefore, these emissions were reviewed pursuant to the requirements for Prevention of Significant Deterioration (PSD), 326 IAC 2-2 and 40 CFR 52.21.

(c) Fugitive Emissions
Since this type of operation is not one of the 28 listed source categories under 326 IAC 2-2 and since there are no applicable New Source Performance Standards that were in effect on August 7, 1980, the fugitive PM emissions are not counted toward determination of PSD and Emission Offset applicability.

Source Status

Existing Source PSD or Emission Offset Definition (emissions after controls, based upon 8760 hours of operation per year at rated capacity and/or as otherwise limited):

Pollutant	**Emissions** (tons/year)
PM	16.89
PM_{10}	16.89
SO_2	79.64
VOC	18.43
CO	181.35
NO_X	Less than 250

(a) This existing source is not a major stationary source because no attainment regulated pollutant is emitted at a rate of 250 tons per year or more, and it is not one of the 28 listed source categories.

(b) These emissions are based upon Page 2 of 12 of the Addendum to the TSD for MSOP 093-14495-00028, issued on March 6, 2002.

Potential to Emit of Revision After Issuance

The table below summarizes the potential to emit, reflecting all limits, of the significant emission units.

	Potential to Emit (tons/year)						
Process/facility	**PM**	**PM_{10}**	**SO_2**	**VOC**	**CO**	**NO_X**	**HAPs**
Proposed Six (6) Turbines (Turbine 1, 2, 3, 4, 5, and 6)	Less than 45.96	Less than 45.96	Less than 148.55	Less than 52.41	Less than 137.57	Less Than 248.93	Single 2.43 Total 3.71
Existing Fire Pump	0.030	0.030	0.080	0.130	0.300	1.07	-

	Potential to Emit (tons/year)						
Process/facility	**PM**	**PM_{10}**	**SO_2**	**VOC**	**CO**	**NO_X**	**HAPs**
Unpaved Roads	16.34	4.08	-	-	-	-	-
Total	Less than 62.60	Less than 50.34	Less than 149.35	Less than 52.54	Less than 137.87	Less Than 250	Single 2.43 Total 3.71
PSD Level	250	250	250	250	250	250	-

Note that limited potential to emit from the six (6) turbines is based on the "worst case" emissions from using either less than a total of 5,324 million cubic feet of natural gas usage per year or less than a total of 21,162,349 gallons per year (See Pages 1 through 6 of 6 of Appendix A).

This revision to the existing MSOP will **not** change the status of the stationary source because the potential emissions from the entire source will still be less than the major PSD source levels.

Federal Rule Applicability

(a) The six (6) turbines, identified as Turbines 1, 2, 3, 4, 5, and 6, are subject to 40 CFR Part 60, Subpart GG because the heat input at peak load is equal to or greater than 10.7 giga-joules per hour, based on the lower heating value of the fuel fired.

Pursuant to 326 IAC 12-1 and 40 CFR 60, Subpart GG (Stationary Gas Turbines), the Permittee shall:

(1) Limit nitrogen oxides emissions, as required by 40 CFR 60.332, to:

$$STD = 0.0075\frac{(14.4)}{Y} + F$$

where STD = allowable NO_X emissions (percent by volume at 15 percent oxygen on a dry basis).

Y = manufacturer's rated heat rate at manufacturer's rated load (kilo-joules per watt hour) or, actual measured heat rate based on lower heating value of fuel as measured at actual peck load for the facility. The value of Y shall not exceed 14.4 kilojoules per watt hour.

F = NO_X emission allowance for fuel-bound nitrogen as defined in paragraph (a)(3) of 40 CFR 60.332.

(2) Operate a Continuous Monitoring System to monitor and record the fuel consumption and the ratio of water to fuel being fired in each turbine as required by 40 CFR 60.334(a);

(3) Limit sulfur dioxide emissions, as required by 40 CFR 60.333, to 0.015 percent by volume at 15 percent oxygen on a dry basis, or use natural gas fuel with a sulfur content less than or equal to 0.8 percent by weight;

(4) Monitor the sulfur content and nitrogen content of the fuel being fired in the turbine, as required by 40 CFR 60.334(b). The custom schedule for the six (6) turbines shall be the following:

Monitor the natural gas combusted through the analysis of pipeline gas from the natural gas supplier. Gas samples shall be taken once a calendar quarter at the closest proximity to the site of the turbines. In the event of less than thirty (30) days of the turbines operation in a quarter, the quarterly sampling is waived. For these purposes, one day of operation shall be defined as any day that gas is burned for more than one (1) hour. Quarterly sampling and analysis of the gas shall be performed according to ASTM methods in 60.335(a) and 60.335(d); and

(5) Report periods of excess emissions, as required by 40 CFR 60.334(c).

(b) There are no National Emission Standards for Hazardous Air Pollutants (NESHAPs) (326 IAC 14, 326 IAC 20, 40 CFR 61 and 40 CFR Part 63) applicable to this proposed revision.

(c) The requirements of Section 112(j) of the Clean Air Act (40 CFR Part 63.50 through 63.56) are not applicable to this source because the source is not a major source of hazardous air pollutant (HAP) emissions (i.e., the source does not have the potential to emit ten (10) tons per year or greater of a single HAP or twenty-five (25) tons per year or greater of a combination of HAPs).

(d) This significant permit revision does not involve a pollutant-specific emission unit:

(1) with the potential to emit before controls equal to or greater than one hundred (100) tons per year, and

(2) that is subject to an emission limit and has a control device that is necessary to meet that limit.

Therefore, the requirements of 40 CFR Part 64, Compliance Assurance Monitoring, are not applicable to this revision.

(e) Hoosier Energy is subject to the requirements of 40 CFR 72 through 40 CFR 78. In conjunction with the construction permit MSOP 093-14495-00028, issued on March 6, 2002, Hoosier Energy - Lawrence County Station was issued a Phase II Acid Rain Permit AR 093-14497-00028 on March 6, 2002. As a result of this pending revision, Hoosier Energy - Lawrence County Station has also applied for a revision to its Phase II Acid Rain Permit, known as Acid Rain Revision 093-16655-00028, and will reflect the new emission units.

Condition D.1.10(c) and (d) of MSOP 093-14495-00028, issued on March 6, 2002 required the use of continuous emissions monitoring systems (CEMS) for NO_X and CO emissions in order to demonstrate compliance with 40 CFR 75 Subpart D. Pursuant to Appendix E to 40 CFR 75, fuel oil or natural gas-fired peaking generation units can use an optional NO_X emission estimation protocol in lieu of a CEMS for NO_X. Subsequently, Indiana Municipal Power Agency (IMPA) was permitted by IDEM, OAQ in Conditions D.1.8, D.1.15, and D.1.16 (f) of SSM 095-15883-00028, issued on November 8, 2002, to use an estimation protocol for NO_X emissions instead of CEMS for their natural gas-fired turbines to comply with the requirements of 40 CFR 75. Hoosier Energy - Lawrence County Station and Indiana Municipal Power Agency (IMPA) (Plt. ID 095-00028) are both peaking power generating sources that have simple cycle natural gas-fired turbines. Therefore, due to the similarities between the two (2) sources, Hoosier Energy has requested to use the same

protocol for monitoring NO_X emissions as IMPA used in their significant source modification.

Upon further review, IDEM, OAQ has determined that pursuant to Appendix E to 40 CFR 75, Hoosier Energy - Lawrence County Station can use a protocol for monitoring NO_X emissions in lieu of a CEMS. Since Hoosier Energy - Lawrence Station has elected to use IMPA's protocol, the requirements of Conditions D.1.8, D.1.15, and D.1.16(f) of SSM 095-15583-00028, will be incorporated into this significant permit revision. See the Proposed Changes Section of this document for details of the incorporated protocol.

Note that all CEMS requirements will not be incorporated in this significant permit revision. For details regarding why CEMS has been removed as a result of this revision see the Compliance Requirements Section of this document.

State Rule Applicability - Individual Facilities

326 IAC 2-2 (Prevention of Significant Deterioration (PSD))

In order to render the requirements of 326 IAC 2-2 and 40 CFR 52.21 not applicable to this source, the facilities at this source are subject to the following:

(a) The pipeline natural gas usage from the six (6) turbines shall be limited to less than 5,324 million standard cubic feet per twelve (12) consecutive month period with compliance determined at the end of each month equivalent to the following:

(1) Less than 248.93 tons of NO_X per year including start-up and shutdown, based on:

(A) An NO_X emission rate of 0.0988 pounds per million British thermal units heat input when combusting natural gas, and

(B) An NO_X emission rate of 0.1693 pounds per million British thermal units heat input when combusting No. 2 fuel oil.

(2) Less than 137.57 tons of CO per year including start-up and shutdown, based on:

(A) A CO emission rate of 0.0546 pounds per million British thermal units heat input when combusting natural gas, and

(B) A CO emission rate of 0.0547 pounds per million British thermal units heat input when combustion No. 2 fuel oil.

(3) Less than 148.55 tons of SO_2 per year, based on:

(A) An SO_2 emission rate of 0.0006 pounds per million British thermal units heat input when combusting natural gas, and

(B) An SO_2 emission rate of 0.1010 pounds per million British thermal units heat input when combusting No. 2 fuel oil.

For purposes of determining compliance based on NO_X, 1,000 gallons of No. 2 fuel oil is equivalent to 0.2516 million standard cubic feet of natural gas.

Note that the natural gas / No. 2 fuel oil equivalency has been calculated based on both the natural gas and No. 2 fuel oil usage limitations that are equivalent to less than 248.93 tons of NO_X per year (See Page 6 of 6 of Appendix A in this document).

(b) Pursuant to Condition D.1.1(b) of MSOP 093-14495-00028, issued on March 6, 2002, the operation of the existing emergency diesel fire pump shall be limited to 500 hours per year.

(c) Pursuant to Condition D.1.1(c) of MSOP 093-14495-00028, issued on March 6, 2002, the sulfur content of No. 2 fuel oil shall not exceed 0.05 percent by weight.

326 IAC 2-4.1-1 (New Source Toxics Control)

The six (6) turbines, identified as Turbines 1, 2, 3, 4, 5, and 6, are not subject to the requirements of 326 IAC 2-4.1-1 (New Source Toxics Control) because the potential to emit each individual hazardous air pollutant (HAP) is less than ten (10) tons per year and the potential to emit total HAPs is less than a total of twenty-five (25) tons per year, total.

326 IAC 6-2-4 (Particulate Limitations for Facilities Constructed after September 21, 1983)

The six (6) turbines, identified as Turbines 1, 2, 3, 4, 5, and 6, are not subject to the requirements of 326 IAC 6-2-4 (Particulate Emissions Limitations for Facilities Constructed after September 21, 1983) because these combustion units are not used for indirect heating.

326 IAC 7-1.1 (Sulfur Dioxide Emission Limitations)

Since the potential to emit sulfur dioxide exceeds ten (10) pounds per hour when combusting No. 2 fuel oil in each of the six (6) turbines, identified as Turbines 1, 2, 3, 4, 5, and 6, each will be subject to 326 IAC 7-1.1. Pursuant to 326 IAC 7-1.1, sulfur dioxide (SO_2) emissions from each turbine when burning No. 2 fuel oil shall be limited to 0.5 pounds per million British thermal units heat input. The six (6) turbines comply with this rule when combusting natural gas and No. 2 fuel oil.

326 IAC 8-1-6 (New facilities; general reduction requirements):

The potential to emit VOC from each of the six (6) turbines, identified as Turbines 1, 2, 3, 4, 5, and 6, are limited to less than twenty-five (25) tons per year by fuel usage limitations that render the requirements of 326 IAC 2-2 and 40 CFR 52.21 not applicable. Therefore, the requirements of 326 IAC 8-1-6 are not applicable.

326 IAC 9-1 (Carbon Monoxide Emission Limits):

This source is subject to 326 IAC 9-1 because it is a stationary source of CO emissions commencing operation after March 21, 1972. There are no applicable CO emission limits, under this state rule, established for this type of operation.

326 IAC 10-4 (NOx Budget Trading Program)

Pursuant to 326 IAC 10-4-2(16) the six (6) turbines (Turbines 1, 2, 3, 4, 5, and 6) are considered "electricity generating units (EGUs)" because they will commence operation after January 1, 1999 and will serve a generator at any time that has a nameplate capacity greater than twenty-five (25) megawatts that will produce electricity for sale under a firm contract to the electric grid. Pursuant to 326 IAC 10-4-1(a)(1), an "EGU" is a NO_X budget unit. Because this source meets the criteria of having one (1) or more NO_X budget units, it is a NO_X budget source. The Permittee shall be subject

to the requirements of this rule.

Since these units will commence operation after May 1, 2000, these units were not allocated NO_X allowances for the 2004, 2005, and 2006 ozone seasons from the existing EGU budget under 326 IAC 10-4-9(b)(1)(A). Therefore, if the NO_X authorized account representative requires NO_X allowances to be allocated, the NO_X authorized account representative shall submit a written request to the IDEM, OAQ for NO_X allowances in accordance with 326 IAC 10-4-9(e)(2) and (3).

Pursuant to 326 IAC 10-4-12(c), the Permittee shall install the appropriate monitoring systems and complete all certification tests as required by 326 IAC 10-4-12(b)(1) through (3) on or before the date specified in 326 IAC 10-4-12(c)(4) since reporting will be on a control season basis under 326 IAC 10-4-12(o)(4). The Permittee shall record, report, and quality assure the data from the monitoring systems on and after the date specified in 326 IAC 10-4-12(c)(4) since reporting will be on a control season basis under 326 IAC 10-4-12(o)(4).

Compliance Requirements

Permits issued under 326 IAC 2-6.1 are required to ensure that sources can demonstrate compliance with applicable state and federal rules on a more or less continuous basis. All state and federal rules contain compliance provisions, however, these provisions do not always fulfill the requirement for a more or less continuous demonstration. When this occurs IDEM, OAQ, in conjunction with the source, must develop specific conditions to satisfy 326 IAC 2-6.1. As a result, compliance requirements are divided into two sections: Compliance Determination Requirements and Compliance Monitoring Requirements.

Compliance Determination Requirements in Section D of the permit are those conditions that are found more or less directly within state and federal rules and the violation of which serves as grounds for enforcement action. If these conditions are not sufficient to demonstrate continuous compliance, they will be supplemented with Compliance Monitoring Requirements, also Section D of the permit. Unlike Compliance Determination Requirements, failure to meet Compliance Monitoring conditions would serve as a trigger for corrective actions and not grounds for enforcement action. However, a violation in relation to a compliance monitoring condition will arise through a source's failure to take the appropriate corrective actions within a specific time period.

The compliance monitoring requirements applicable to this source are as follows:

(a) The six (6) turbines, identified as Turbines 1, 2, 3, 4, 5, and 6 have applicable compliance monitoring conditions as specified below:

(b) Once per shift visible emissions notations of the six (6) turbines (Turbines 1, 2, 3, 4, 5, and 6) shall be performed during normal daylight operations when combusting No. 2 fuel oil. A trained employee will record whether emissions are normal or abnormal. For processes operated continuously "normal" means those conditions prevailing, or expected to prevail, eighty percent (80%) of the time the process is in operation, not counting startup or shut down time. In the case of batch or discontinuous operations, readings shall be taken during that part of the operation that would normally be expected to cause the greatest emissions. A trained employee is an employee who has worked at the plant at least one (1) month and has been trained in the appearance and characteristics of normal visible emissions for that specific process. The Preventive Maintenance Plan for this unit shall contain trouble-shooting contingency and corrective actions for when an abnormal emission is observed.

(c) Hoosier Energy REC - Lawrence County Station is no longer required to install a continuous emissions monitoring system (CEMS) for NO_X or CO because the natural gas with equival-

ent No. 2 fuel oil usage limit and any required record keeping and reporting implemented to demonstrate compliance with that usage limit is sufficient evidence to determine that this source is a minor PSD source. In addition, CEMS is also not required pursuant to Appendix E to 40 CFR 75, because an alternative NO_X emissions monitoring protocol is being incorporated in place of CEMS.

Proposed Changes

The permit language is changed to read as follows (deleted language appears as ~~strikeouts~~, new language appears in bold):

SECTION A SOURCE SUMMARY

This permit is based on information requested by the Indiana Department of Environmental Management (IDEM), Office of Air Quality (OAQ). The information describing the source contained in Conditions A.1 ~~through~~ **and** A.~~3~~**2** is descriptive information and does not constitute enforceable conditions. However, the Permittee should be aware that a physical change or a change in the method of operation that may render this descriptive information obsolete or inaccurate may trigger requirements for the Permittee to obtain additional permits or seek modification of this permit pursuant to 326 IAC 2, or change other applicable requirements presented in the permit application.

A.1 General Information [326 IAC 2-5.1-3(c)] [326 IAC 2-6.1-4(a)]

The Permittee owns and operates a stationary **peaking** power generating facility.

Authorized Individual:	~~Tom Bernardi~~ **Manager Generation Technical Services**
Source Address:	~~3.5 miles SE of Bedford-Northwest Quarter of Section 7, Bedford, Indiana~~\ **1000 S. Old Palistine Road, Mitchell, Indiana 47446**
Mailing Address:	P.O. Box 908, Bloomington, Indiana 47402-0908

A.2 Emissions units and Pollution Control Equipment Summary

This stationary source is approved to construct and operate the following emissions units and pollution control devices:

(a) ~~Four (4)~~ **Six (6)** simple cycle, dual fuel turbine generator units **combusting pipeline natural gas as a primary fuel and No.2 fuel oil as a back-up fuel**, identified as Turbine**s** 1, 2, 3, 4, **5,** and **6,** each with a net generating capacity of ~~103~~ **43.8** ~~MW~~ **megawatts,** ~~per turbine~~**,** and a corresponding heat input capacity of ~~1221~~ **384.44** ~~MMBtu/hr~~ **million British thermal units per hour, each**, ~~using dry low NOx emission control~~ **equipped with water injection** ~~as~~ **for NO_X** control, and exhausting to ~~s~~**S**tack**s** 1, 2, 3, 4, **5,** and **6,** respectively. ~~The primary fuel will be natural gas, with fuel oil used as a back-up.~~

(b) One (1) diesel fuel storage tank, identified as #1, with a maximum capacity of 1,200,000 gallons.

(c) One (1) emergency diesel fire pump, identified as pump 1, with a maximum capacity of 208 HP, and exhausts to stack ~~5~~**7**.

A.4 Acid Rain Permit Applicability [40 CFR Part 72.30]

(b) The source cannot operate the combustion units until ~~their~~ its Phase II, Acid Rain permit has been issued.

SECTION D.1 EMISSIONS UNIT OPERATION CONDITIONS

Facility Description [326 IAC 2-7-5(15)]: Six (6) combustion turbines

(a) ~~Four (4)~~ **Six (6)** simple cycle, dual fuel turbine generator units **combusting pipeline natural gas as a primary fuel and No.2 fuel oil as a back-up fuel**, identified as Turbine**s** 1, 2, 3, 4, **5,** and **6,** each with a net generating capacity of ~~103~~ **43.8** ~~MW~~ **megawatts,** ~~per turbine~~ **each,** and a corresponding heat input capacity of ~~1221~~ **384.44** ~~MMBtu/hr~~ **million British thermal units per hour,** ~~using dry low NOx emission control~~ **equipped with water injection** ~~as~~ **for NO_x** control, and exhausting to ~~s~~**S**tack**s** 1, 2, 3, 4, **5,** and **6,** respectively. ~~The primary fuel will be natural gas, with fuel oil used as a back-up.~~

(b) One (1) diesel fuel storage tank, identified as #1, with a maximum capacity of 1,200,000 gallons.

(c) One (1) emergency diesel fire pump, identified as pump 1, with a maximum capacity of 208 HP, and exhausts to stack ~~5~~**7**.

(The information describing the process contained in this facility description box is descriptive information and does not constitute enforceable conditions.)

D.1.1 PSD Minor Limit [326 IAC 2-2] [40 CFR 52.21]

~~(a) The potential to emit NOx from the four (4) combustion turbines (including startup and shutdown) shall be limited to less than 248.93 tons per twelve (12) consecutive months per pollutant, rolled on monthly basis. The potential to emit CO from the four (4) combustion turbines (including startup and shutdown) shall be limited to less than 249.70 tons per twelve (12) consecutive months per pollutant, rolled on monthly basis. Operating the emergency diesel fire pump shall be limited to 500 hours per year.~~

(a) The pipeline natural gas usage from the six (6) turbines shall be limited to less than 5,324 million standard cubic feet per twelve (12) consecutive month period with compliance determined at the end of each month equivalent to the following:

(1) Less than 248.93 tons of NO_x per year including start-up and shutdown, based on:

(A) An NO_x emission rate of 0.0988 pounds per million British thermal units heat input when combusting natural gas, and

(B) An NO_x emission rate of 0.1693 pounds per million British thermal units heat input when combusting No. 2 fuel oil.

(2) Less than 137.57 tons of CO per year including start-up and shutdown, based on:

(A) A CO emission rate of 0.0546 pounds per million British thermal units heat input when combusting natural gas, and

(B) A CO emission rate of 0.0547 pounds per million British thermal units heat input when combustion No. 2 fuel oil.

(3) Less than 148.55 tons of SO_2 per year, based on:

(A) An SO_2 emission rate of 0.0006 pounds per million British thermal units heat input when combusting natural gas, and

(B) An SO_2 emission rate of 0.1010 pounds per million British thermal units heat input when combusting No. 2 fuel oil.

For purposes of determining compliance based on NO_X, 1,000 gallons of No. 2 fuel oil shall be equivalent to 0.2516 million standard cubic feet of natural gas.

(b) Compliance with these limits and limiting the operation of the emergency diesel fire pump to 500 hours per year makes 326 IAC 2-2 (Preventive of Significant Deterioration) and 40 CFR 52.21 not applicable.

(c) The sulfur content of the fuel oil shall not exceed 0.05 percent by weight.

D.1.2 General Provisions Relating to NSPS [326 IAC 12-1] [40 CFR Part 60, Subpart A]

The provisions of 40 CFR Part 60, Subpart A - General Provisions, which are incorporated by reference in 326 IAC 12-1, apply to the facility described in this section except when otherwise specified in 40 CFR Part 60, Subpart **GG**.

D.1.3 40 CFR Part 60, Subpart GG Applicability (Stationary Gas Turbine)

(a) The ~~four (4)~~ **six (6)** combustion turbines are subject to 40 CFR Part 60, Subpart GG, because the heat input at peak load is equal to or greater than 10.7 gigajoules per hour, based on the lower heating value of the fuel fired.

(b) Pursuant to 326 IAC 12-1 and 40 CFR 60, Subpart GG (Stationary Gas Turbines), the Permittee shall:

(1) limit nitrogen oxides emissions, as required by 40 CFR 60.332, to:

$$STD = 0.0075 \frac{(14.4)}{Y} + F ,$$

where STD = allowable NO_X emissions (percent by volume at 15 percent oxygen on a dry basis).

Y = manufacturer's rated heat rate at manufacturer's rated load (kilojoules per watt hour) or, actual measured heat rate based on lower heating value of fuel as measured at actual peak load for the facility. The value of Y shall not exceed 14.4 kilojoules per watt hour.

F = NO_X emission allowance for fuel-bound nitrogen as defined in paragraph (a)(3) of 40 CFR 60.332.

(2) limit sulfur dioxide emissions, as required by 40 CFR 60.333, to 0.015 percent by volume at 15 percent oxygen on a dry basis, or use natural gas fuel with a sulfur content less than or equal to 0.8 percent by weight.

D.1.7 Preventive Maintenance Plan

A Preventive Maintenance Plan, in accordance with Section C - Preventive Maintenance Plan, of this permit, is required for ~~this~~ **these** emission~~s~~ unit**s** and ~~its~~ **their** control device**s**.

D.1.8 Testing Requirements [326 IAC 2-1.1-11] **[40 CFR 75.12]**

~~(a) Pursuant to 326 IAC 3-5 the Permittee shall conduct a performance test, not later than one-hundred and eighty (180) days after a facility start-up or monitor installation, on the combustion turbines' exhaust stacks (designated as stack 1, 2, 3 and 4) in order to certify the continuous emission monitoring system for NO_x and CO.~~

~~(b) Within sixty (60) days after achieving maximum production rate, but no later than one hundred and eighty (180) days after initial start-up, the Permittee shall conduct NO_x and SO_2 stack tests for each turbine utilizing methods as approved by the Commissioner. These tests shall be performed in accordance with 40 CFR Part 60.335 and Section C - Performance Testing, in order to document compliance with Condition D.1.2.~~

~~(c) IDEM may require compliance testing at any specific time when necessary to determine if the source is in compliance. If testing is required by IDEM, compliance with the NO_x and CO limits specified in Condition D.1.1, shall be determined by a performance test conducted in accordance with Section C - Performance Testing.~~

(a) The Permittee shall perform initial performance tests for Turbines 1, 2, 3, 4, 5, and 6, to measure NO_X emission rates at heat input rate levels corresponding to different load levels and plot the correlation between heat input rate and NO_X emission rate in order to determine the emission rate of the units. The testing shall be performed in accordance with Section 2.1 of Appendix E of 40 CFR 75.

(b) The Permittee shall retest the NO_X emission rate of each turbine prior to the earlier of 3,000 unit operating hours or the five (5) year anniversary and renewal of its operating permit under 40 CFR 72. This testing shall be performed in accordance with Section 2.1 of Appendix E of 40 CFR 75.

~~D.1.10 Continuous Emission Monitoring System (CEMS) [326 IAC 3-5]~~

~~(a) Pursuant to 326 IAC 3-5-1(d)(1), the owner or operator of a new source with an emission limitation or permit requirement established under 326 IAC 2-5.1-3 and 2-6.1 shall be required to install a continuous emissions monitoring system or alternative monitoring plan as allowed under the Clean Air Act and 326 IAC 3-5.~~

~~(b) For NO_x and CO the Permittee shall install, calibrate, certify, operate and maintain a continuous emissions monitoring system for stacks designated as 1, 2, 3 and 4, in accordance with 326 IAC 3-5-2 and 3-5-3.~~

~~(1) The continuous emission monitoring system (CEMS) shall measure NO_x and CO emissions rates in pounds per hour. The use of CEMS to measure and record the NO_x and CO hourly emission rates, is sufficient to demonstrate compliance with the annual limits established in the Condition D.1.1.~~

~~(2) The Permittee shall submit to IDEM, OAQ, within ninety (90) days after monitor installation, a complete written continuous monitoring standard operating procedure (SOP), in accordance with the requirements of 326 IAC 3-5-4.~~

~~(3) The Permittee shall record the output of the system and shall perform the required record keeping, pursuant to 326 IAC 3-5-6, and reporting, pursuant to 326 IAC 3-5-7.~~

~~(c) In instances of downtime, the source shall use EPA's AP-42 emission factors for stationary gas turbines, to demonstrate compliance with the CO emission limit and use the Missing~~

~~Data Substitution Procedures outlined in 40 CFR Part 75, Subpart D to demonstrate compliance with the NO_x emission limit, established under Condition D.1.1.~~

~~(d) The source may submit to OAQ alternative emission factors based on the source's CEMS data, to use in lieu of the AP-42 emission factors in instances of downtime. The alternative emissions factors must be approved by OAQ prior to use in calculating emissions for the limitations established in this construction permit. The alternative emission factors shall be based upon collected monitoring and test data supplied from an approved continuous emission monitoring system and/or approved performance tests. In the event that the information submitted does not contain sufficient data to establish appropriate emission factors, the source shall continue to collect data until appropriate emission factors can be established. During this period of time, the source shall continue to use AP-42 emission factors for CO and the NO_x. Missing Data Substitution Procedures specified in 40 CFR Part 75, Subpart D, in periods of downtime.~~

D.1.~~11~~ **10** 326 IAC 7-2 [Sulfur Content Compliance]

Pursuant to 326 IAC 7-2-1, the Permittee shall demonstrate that the fuel oil sulfur content does not exceed 0.5 pounds per million Btu (lb/MMBtu) by:

(a) Fuel sampling and analysis data shall be collected pursuant to procedures specified in 326 IAC 3-7-4 for oil combustion, and these data may be used to determine compliance or non-compliance with the emission limitations contained in 326 IAC 7-1.1. Computation of calculated sulfur dioxide emission rates from fuel sampling and analysis data shall be based on AP-42 emission factors, unless other emission factors based on site specific sulfur dioxide measurements are approved by the commissioner and the U.S. EPA. Fuel sampling and analysis data shall be collected as follows:

compliance or noncompliance shall be determined by using a calendar month average sulfur dioxide emission rate in pounds per million Btu unless a shorter averaging time or alternate methodology is specified under 326 IAC 7-2. Analyzing the oil sample to determine the sulfur content of the oil via the procedures in 40 CFR 60, Appendix A, Method 19.

~~(i)~~ **(1)** Oil samples may be collected from the fuel tank immediately after the fuel tank is filled and before any oil is combusted; and

~~(ii)~~ **(2)** If a partially empty fuel tank is refilled, a new sample and analysis would be required upon filling.

(b) Compliance or noncompliance with the emission limitation specified in 326 IAC 7-1.1 may be determined by conducting a stack test for sulfur dioxide emissions from the ~~four (4)~~ **six (6)** combustion turbines, using 40 CFR 60, Appendix A, Method 6, 6A, 6C, or 8, in accordance with the procedures in 326 IAC 3-6.

~~(c) Upon written notification of a facility owner or operator to the department, continuous emission monitoring data collected and reported pursuant to 326 IAC 3-5 may be used as the means for determining compliance.~~

~~(d)~~ **(c)** A determination of noncompliance pursuant to either of the methods specified in (a) or (b) ~~(c)~~ above shall not be refuted by evidence of compliance pursuant to the other method.

D.1.11 Nitrogen Oxides Monitoring Requirement [326 IAC 10-4-4(b)(1)] [326 IAC 10-4-12(b) and (c)] [40 CFR 75]

The Permittee shall meet the monitoring requirements of 326 IAC 10-4-12(b)(1) through (b)(3) that are applicable to their monitoring systems for the NO_x budget units on or before the later of the dates listed in paragraphs (a) and (b). The Permittee shall record, report, and quality assure the data from the monitoring systems on and after the later of the following dates in accordance with 326 IAC 10-4-12 and 40 CFR 75:

(a) May 1, 2003.

(b) The earlier of:

(1) one hundred eighty (180) days after the date on which the first unit commences operation; or

(2) ninety (90) days after the date the first unit commences commercial operation.

Compliance Monitoring Requirements [326 IAC 2-5.1-3(e)(2)] [326 IAC 2-6.1-5(a)(2)]

D.1.12 Visible Emissions Notations

(a) Visible emission notations of the Turbines 1, 2, 3, 4, 5, and 6 stack exhausts shall be performed once per shift during normal daylight operation when combusting No. 2 fuel oil. A trained employee shall record whether emissions are normal or abnormal.

(b) For processes operated continuously, "normal" means those conditions prevailing, or expected to prevail, eighty percent (80%) of the time the process is in operation, not counting startup or shut down time.

(c) In the case of batch or discontinuous operations, readings shall be taken during that part of the operation that would normally be expected to cause the greatest emissions.

(d) A trained employee is an employee who has worked at the plant at least one (1) month and has been trained in the appearance and characteristics of normal visible emissions for that specific process.

(e) The Compliance Response Plan for this unit shall contain troubleshooting contingency and response steps for when an abnormal emission is observed. Failure to take response steps in accordance with Section C - Compliance Response Plan - Preparation and Implementation shall be considered a violation of this permit.

D.1.13 NO_x Monitoring [40 CFR 75.12(d)]

(a) Pursuant to 40 CFR 72.9 and 40 CFR 75.12, the Permittee has elected to monitor NO_x emissions from the six (6) combustion turbines pursuant to 40 CFR 75, Appendix E, which is used for peaking units. Appendix E includes, but is not limited to, the following requirements:

(1) The Permittee shall perform initial performance tests for each turbine to measure NO_x emission rates at heat input rate levels corresponding to different load levels and plot the correlation between heat input rate and NO_x emission rate in order to determine the emission rate of the units. This testing shall be

performed in accordance with Section 2.1 of Appendix E.

(2) The Permittee shall retest the NO_x emission rate for the turbines prior to the earlier of 3,000 unit operating hours or the five (5) year anniversary and renewal of its operating permit under 40 CFR Part 72.

(3) The Permittee shall record the time (hour and minute), load (megawatt), fuel flow rate and heat input rate (using the procedures in Section 2.1.3 of Appendix E) for each hour during which the unit combusts fuel. The Permittee shall calculate the total hourly heat input using equation E-1 of Appendix E and record the heat input rate for each fuel to the nearest 0.1 million British thermal units per hour. During partial unit operating hours, heat input must be represented as an hourly rate in million British thermal units per hour, as if the fuel were combusted for the entire hour at that rate in order to ensure proper correlation with the NO_x emission rate graph.

(4) The Permittee shall use the graph of the baseline correlation results to determine the NO_x emission rate (pounds per million British thermal units) corresponding to the heat input rate (million British thermal units per hour) and input this correlations into the data acquisition and handling system for the turbines. The data shall be linearly interpolation to 0.1 million British thermal units per hour heat input rate and 0.01 pounds per million British thermal units.

(b) If any combustion turbine exceeds a capacity factor of twenty percent (20%) in any given year, or exceeds an average capacity factor of ten percent (10%) for the previous three (3) years, then the Permittee shall install, certify, and operate an NO_x continuous emissions monitoring system (CEMS) by December 31 of the following calendar year on that turbine. The NO_x CEMS shall meet the minimum requirements of 40 CFR Part 75 and 326 IAC 3-5. If the required CEMS has not been installed and certified by that date, the Permittee shall report the maximum potential NO_x emission rate (MER) (as defined in 40 CFR 72.2) for each unit operating hour, starting with the first unit operating hour after the deadline and continuing until the CEMS has been provisionally certified.

D.1.~~12~~ **14** Record Keeping Requirements

(a) To document compliance with Conditions D.1.1 the Permittee shall maintain records of the following:

(1) amount of natural gas combusted (in million **standard** cubic feet) and **No. 2** fuel oil (in gallons) per unit (turbine, heating equipment and fire pump engine) during each month;

(2) the percent sulfur content of the natural gas (if other than pipeline quality natural gas which is defined as natural gas that is provided by a supplier through a pipeline; 40 CFR Part 72.2) and **No. 2** fuel oil of each unit (turbine and fire pump engine); **and**

~~(3) the emission rates of NO_x and CO in pounds per hour (based on CEMS data); and~~

~~(4)~~ **(3)** the Permittee shall maintain records required under 326 IAC 3-5-6 at the source in a manner so that they may be inspected by the IDEM, OAQ, or the U.S. EPA, if so

requested or required.

(b) To document compliance with D.1.~~2~~ **3**, the source shall maintain records of the natural gas analyses, including the sulfur and nitrogen content of the gas, for a period of three (3) years.

(c) To document compliance with Condition D.1.~~3~~ **4**, the Permittee shall:

(1) maintain the records of the volatile organic liquid (VOL) stored;

(2) the period of storage;

(3) the maximum true vapor pressure of the volatile organic liquid (VOL) during the respective storage period; and

(4) shall keep readily accessible records showing the dimension of the storage vessel and an analysis showing the capacity of the storage vessel.

(d) To document compliance with Condition D.1.13, the Permittee shall record the time (hour and minute), load (megawatt), fuel flow rate and heat input (using the procedures in Section 2.1.3 of Appendix E) for each fuel to the nearest 0.1 million British thermal units per hour. During partial unit operating hours, heat input must be represented as an hourly rate in million British thermal units per hour, as if the fuel were combusted for the entire hour at that rate in order to ensure proper correlation to the NO_x emission rate graph.

~~(d)~~ **(e)** All records shall be maintained in accordance with Section C – General Record Keeping Requirements, of this permit.

D.1.15 Nitrogen Oxides Budget Trading Program [326 IAC 10-4-4(a)(1)] [326 IAC 10-4-9(e)(2)]

For NO_x budget units that will commence operation on or after May 1, 2000, the NO_x authorized account representative shall submit a request for NO_x allowances in accordance with 326 IAC 10-4-9(e) by September 1 of the calendar year that is one (1) year in advance of the first ozone control period for which the NO_x allowance allocation is requested. The NO_x authorized account representative shall submit a request each year that the units will require allowances from the new unit set aside until the units are allocated allowances from the existing source pool. These requests shall be submitted by the NO_x authorized account representative to:

Indiana Department of Environmental Management
Compliance Branch, Office of Air Quality
100 North Senate Avenue, P.O. Box 6015
Indianapolis, Indiana 46206-6015

D.1.~~13~~ **16** Reporting Requirements

~~(a) The Permittee shall submit a quarterly emissions report, if applicable, based on the continuous emissions monitor (CEM) data for NO_x and CO , pursuant to 326 IAC 3-5-7. These reports shall be submitted within thirty (30) calendar days following the end of each calendar quarter and in accordance with Section C - General Reporting Requirements of this permit. To convert the CEMS data from ppm to tons per month as requested in the report forms, the source needs to use the following formulae Pursuant to 40 CFR 75 (Appendix F):~~

~~$E = K C_h F (20.9 / (20.9 - \% O2))$~~

~~Where:~~

~~E =Pollutant emissions in lb/MMBtu.~~
~~K =1.194 x 10^{-7} (lb/dscf)/ppm NO_x~~
~~C_h =Hourly average pollutant concentration in ppm.~~
~~F =a factor representing a ratio of the volume of dry flue gases generated to the caloric value of the fuel combusted.~~
~~For Oil, F=9,190 (dscf/MMBtu) and For Natural gas, F = 8,710 (dscf/MMBtu)~~

~~The average NOx emission rate for each calendar month~~

$$E_m = \frac{\sum_{i=1}^{n} Ei}{n}$$

~~Where:~~

~~Em =Monthly average NOx emission rate (lb/MMBtu)~~
~~Ei =Hourly average NOx emisson rate (lb/MMBtu)~~
~~n =Number of hourly rates during calendar month~~

~~(b)~~ **(a)** A quarterly summary of the information to document compliance with **Condition** D.1.1 shall be submitted to the address listed in Section C - General Reporting Requirements, of this permit, using the reporting forms located at the end of this permit, or their equivalent, within thirty (30) days after the end of the quarter being reported.

~~(c)~~ **(b)** The Permittee shall report periods of excess emissions, as required by 40 CFR 60.334(c).

~~(d)~~ **(c)** The Permittee shall submit reports of calendar month average sulfur content, heat content, fuel consumption, and sulfur dioxide emission rate in pounds per million Btu upon request based on fuel sampling and analysis data in accordance with procedures specified under 326 IAC 3-7-4 to document compliance with **Condition** D.1.10.

~~(e)~~ **(d)** These reports shall be submitted within thirty (30) calendar days following the end of each calendar quarter and shall be in accordance with Section C – General Reporting Requirements of this permit.

Indiana Department of Environmental Management
Office of Air Quality
Compliance Data Section

Quarterly Report

Company Name: Hoosier Energy Bedford Station
Location: 3.5 miles SE of Bedford-Northwest Quarter of section 7, Bedford, Indiana
Permit No.: 093-14495-00028
Source: Four (4) combustion turbines and one (1) diesel-fired engine
Pollutant: CO
Limit: Less than 250 tons per twelve (12) consecutive month period

Year: _____

Month	CO Emissions (tons/month)	Total CO emissions for previous eleven month (tons/month)	Total CO for twelve month period (tons)
1			
2			
3			

9 No deviation occurred in this quarter.

9 Deviation/s occurred in this quarter.
Deviation has been reported on: _____

Submitted by: _____

Title/Position: _____

Signature: _____

Date: _____

Indiana Department of Environmental Management
Office of Air Quality
Compliance Data Section

Quarterly Report

Company Name: Hoosier Energy Lawrence County Station
Location: 3.5 miles SE of Bedford-Northwest Quarter of section 7, Bedford, Indiana
Permit No.: 093-14495-00028
Source: Four (4) combustion turbines and one (1) diesel-fired engine
Pollutant: NO_x
Limit: Less than 250 tons per twelve (12) consecutive month period

Year: _____

Month	NOx Emissions (tons/month)	Total NOx emissions for previous eleven month (tons/month)	Total NOx for twelve month period (tons)
1			
2			
3			

9 No deviation occurred in this quarter.

9 Deviation/s occurred in this quarter.
Deviation has been reported on: _____

Submitted by: _____

Title/Position: _____

Signature: _____

Date: _____

INDIANA DEPARTMENT OF ENVIRONMENTAL MANAGEMENT
OFFICE OF AIR QUALITY
COMPLIANCE DATA SECTION

Part 70 Quarterly Report

Source Name: Hoosier Energy - Lawrence County Station
Source Address: 1000 S. Old Palistine Road, Mitchell, Indiana 47446
Mailing Address: P.O. Box 908, Bloomington, Indiana 47402-0908
Permit No.: MSOP 093-14495-00028
Facilities: Six (6) Combustion Turbines
Parameter: Fuel Usage
Limit: Less than a total of 5,324 million standard cubic feet of natural gas per twelve (12) consecutive month period with compliance determined at the end of each month where 1000 gallons of No. 2 fuel oil shall be equivalent to 0.2516 million standard cubic feet of natural gas equivalent to less than 248.93 tons of NO_X per year, less than 137.57 tons of CO per year, and less than 148.55 tons of SO_2 per year.

YEAR: _____

Month	Fuel Usage This Month	Fuel Usage Previous 11 Months	Fuel Usage 12 Month Total
	Natural Gas (mmscf) Including Equivalent No. 2 Fuel Oil	Natural Gas (mmscf) Including Equivalent No. 2 Fuel Oil	Natural Gas (mmscf) Including Equivalent No. 2 Fuel Oil

9 **No deviation occurred in this month.**

9 **Deviation/s occurred in this month.**

Deviation has been reported on: _____

Submitted by: _____

Title/Position: _____

Signature: _____

Date: _____

Phone: _____

Attach a signed certification to complete this report.

The source's company address was changed in the MSOP Annual Notification Form as follows

Company Name:	**Hoosier Energy - Lawrence County Station**
Address:	**1000 S. Old Palistine Road**
City:	**Mitchell, Indiana 47446**
Phone #:	**(812) 876-2021**
MSOP #:	**093-14495-00028**

Numbers 4 and 5 of the affidavit of construction as follows:

4. I hereby certify that Hoosier Energy **-** Lawrence County Station, ~~3.5 miles SE of Bedford-Northwest Quarter of Section 7, Indiana~~ **1000 S. Old Palistine Road, Mitchell, Indiana 47446**, completed construction of **six (6) combustion turbines** the stationary **peaking** power generating facility on _____in conformity with the requirements and intent of the construction permit application received by the Office of Air Quality on June 25, 2001 and as permitted pursuant to ~~Construction Permit No.~~ ~~CP~~ **Significant Permit Revision No.** 093-~~14495~~ **16653**, Plant ID No. 093-00028 issued on _____

5. I hereby certify that Hoosier Energy - ~~Bedford~~ **Lawrence County** Station is now subject to the Title V program and will submit a Title V (or FESOP) operating permit application within twelve (12) months from the postmarked submission date of this Affidavit of Construction.

Conclusion

The construction and operation of this proposed revision shall be subject to the conditions of the attached proposed MSOP Significant Permit Revision No. SPR 093-16653-00028.

Appendix A: Emissions Calculations
Natural Gas Combustion Only
Turbines 1 - 6

Company Name: Hoosier Energy - Lawrence County Station
Address City IN Zip: 3.5 Miles SE of Bedford-Northwest Quarter of Section 7
MSOP Revision: SPR 093-16653
Plt ID: 093-00028
Reviewer: Michael S. Schaffer
Date: October 11, 2002

Emissions Limitations for Revision

Pollutant	PM (tons/yr)	PM-10 (tons/yr)	SO2 (tons/yr)	NOx (tons/yr)	VOC (tons/yr)	CO (tons/yr)
Limit	250	250	250	250	250	250
Fire Pump (Pump 1)	0.030	0.030	0.080	1.07	0.130	0.300
Limit For Turbines	249.97	249.97	249.92	248.93	249.87	249.70

For detailed fire pump emissions calculations see the Appendix A to the TSD of MSOP 093-14485-00028

Heat Output Capacity to Heat Input Capacity Conversion For Natural Gas

Nameplate Capacity of Each Turbine (kW)	Conversion Factor (Btu/kW-hr)	Heat Input Capacity of Each Turbine (Btu/hr)	Heat Input Capacity of Each Turbine (MMBtu/hr)
43771	8783	384440693.00	**384.44**

Methodology
Nameplate capacity in kilowatts (kw) x conversion factor in Btu/kW-hr = Heat input capacity in Btu
Heat input capacity in Btu/hr / 1,000,000 = Heat input capcity in MMBtu/hr

Potential Natural Gas Usage of The Six (6) Turbines

Heat Input Capacity (Btu/hr)	Heat Content of Natural Gas (Btu/cf)	Potential Natural Gas Usage Rate (cf/hr)	Potential Natural Gas Usage Rate (mmcf/hr)
384440693	946	406386	**0.406**

Methodology
Heat input capacity in Btu/hr / heat content of natural gas in Btu/cf = Natural gas usage rate in cf/hr
Natural gas usage rate in cf/hr / 1,000,000 = Natural gas usage rate in mmcf/hr

Appendix A: Emissions Calculations
Natural Gas Combustion Only
Turbines 1 - 6

Company Name: **Hoosier Energy - Lawrence County Station**
Address City IN Zip: **3.5 Miles SE of Bedford-Northwest Quarter of Section 7**
MSOP Revision: **SPR 093-16653**
Plt ID: **093-00028**
Reviewer: **Michael S. Schaffer**
Date: **October 11, 2002**

Calculated lb/MMBtu Natural Gas Emission Factors

Pollutant	Vendor Guarantee Emission Rate (lb/hr)	Heat Input Capacity (MMBtu/hr)	Emission Factor (lb/MMBtu)
PM	3.00	384.44	0.00780
PM-10	3.00	384.44	0.00780
SO2*	N/A	384.44	0.00060
NOx	38.0	384.44	0.09884
VOC	8.00	384.44	0.02081
CO	21.0	384.44	0.05462

Methodology
Vender Guarantee Emission Rate in lb/hr / heat input capacity in MMBtu/hr = Emission Factor in lb/MMBtu
* lb MMBtu emission factor SO2 is based on AP-42

Worst Case Natural Gas Usage Determination

Pollutant	Limit for Turbines (tons/yr)	Conversion Factor (lbs/ton)	Emission Rate of Pollutant (lb/hr)	Source-wide Potential Natural Gas Usage Rate (mmcf/hr)	Potential Natural Gas Usage Rate Limit For Each Pollutant (mmcf/yr)
PM	249.97	2000	3.00	0.406	67723
PM-10	249.97	2000	3.00	0.406	67723
SO2	249.92	2000	0.230	0.406	883164
NOx	**248.93**	**2000**	**38.0**	**0.406**	**5324**
VOC	249.87	2000	8.00	0.406	25386
CO	249.70	2000	21.0	0.406	9664

Methodology
(Limit for tubines in tons/yr x 2000 lbs/ton / Emission Rate of Pollutant) x Source-wide potential natural gas usage rate in mmcf/hr =
Potential natural gas usage rate for each pollutant in mmcf/hr
Note than NOx is the worst case pollutant, thus, the source-wide natural gas usage limit will be based on 5,324 mmcf/yr

Appendix A: Emissions Calculations
Natural Gas Combustion Only
Turbines 1 - 6

Company Name: **Hoosier Energy - Lawrence County Station**
Address City IN Zip: **3.5 Miles SE of Bedford-Northwest Quarter of Section 7**
MSOP Revision: **SPR 093-16653**
Plt ID: **093-00028**
Reviewer: **Michael S. Schaffer**
Date: **October 11, 2002**

Equivalent Heat Input Capacity Based On Natural Gas Usage Limitation For The Six (6) Turbines

Source-wide Natural Gas Usage Limitation (mmcf/yr)	Source-wide Natural Gas Usage Limitation (cf/yr)	Heat Content of Natural Gas (Btu/cf)	Heat Content of Natural Gas (MMBtu/cf)	Equivalent Heat Input Capacity (MMBtu/yr)
5324	5324291850	946	0.000946	**5036780**

Methodology
Source-wide natural gas usage in mmcf/yr x 10^6 = Source-wide natural gas usage in cf/yr
Heat content of natural gas in Btu/cf / 10^6 = Heat content of natural gas in MMBtu/cf
Source-wide natural gas usage limitation in cf/yr x Heat content of natural gas in MMBtu/cf = Equivalent heat input capacity MMBtu/yr

Annual Emissions For Natural Gas Usage Limitation Based On Worst Case Pollutant (NOx)

Pollutant	Equivalent Heat Input Capacity (MMBtu/yr)	Emission Factor (lb/MMBtu)	Conversion Factor (lbs/ton)	Limited Potential to Emit (tons/yr)
PM	5036780	0.00780	2000	**19.65**
PM-10	5036780	0.00780	2000	**19.65**
SO2	5036780	0.00060	2000	**1.51**
NOx	5036780	0.09884	2000	**248.93**
VOC	5036780	0.02081	2000	**52.41**
CO	5036780	0.05462	2000	**137.57**

Methodology
(Equivalent heat input capacity in MMBtu/yr x Emission factor in lb/MMBtu) / (2000 lbs/ton) = Limited potential to emit in tons/yr

Appendix A: Emissions Calculations
No. 2 Fuel Oil Combustion Only
Turbines 1 - 6

Company Name: **Hoosier Energy - Lawrence County Station**
Address City IN Zip: **3.5 Miles SE of Bedford-Northwest Quarter of Section 7**
MSOP Revision: **SPR 093-16653**
Plt ID: **093-00028**
Reviewer: **Michael S. Schaffer**
Date: **October 11, 2002**

Emissions Limitations for Revision

Pollutant	PM (tons/yr)	PM-10 (tons/yr)	SO2 (tons/yr)	NOx (tons/yr)	VOC (tons/yr)	CO (tons/yr)
Limit	250	250	250	250	250	250
Fire Pump (Pump 1)	0.030	0.030	0.080	1.07	0.130	0.300
Limit For Turbines	249.97	249.97	249.92	248.93	249.87	249.70

For detailed fire pump emissions calculations see the Appendix A to the TSD of MSOP 093-14485-00028

Heat Output Capacity to Heat Input Capacity Conversion For No. 2 Fuel Oil

Nameplate Capacity of Each Turbine (kW)	Conversion Factor (Btu/kW-hr)	Heat Input Capacity of Each Turbine (Btu/hr)	Heat Input Capacity of Each Turbine (MMBtu/hr)
42872	8958	384047376	**384.05**

Methodology
Nameplate capacity in kilowatts (kw) x conversion factor in Btu/kW-hr = heat input capacity in Btu
Heat input capacity in Btu/hr / 1,000,000 = heat input capcity in MMBtu/hr

Potential No. 2 Fuel Oil Usage in the Six (6) Turbines

Heat Input Capacity (Btu/hr)	Heat Content of No. 2 Fuel Oil (Btu/gal)	Potential No. 2 Fuel Oil Usage Rate (gal/hr)	Potential No. 2 Fuel Oil Usage Rate (kgal/hr)
384047376	139000	2763	**2.763**

Methodology
Heat input capacity in Btu/hr / heat content of No. 2 fuel oil in Btu/gal = Potential No. 2 fuel oil usage rate in gal/hr
No.2 fuel oil usage rate in gal/hr / 1,000,000 = No. 2 fuel oil usage rate in kgal/hr

Appendix A: Emissions Calculations
No. 2 Fuel Oil Combustion Only
Turbines 1 - 6

Company Name: **Hoosier Energy - Lawrence County Station**
Address City IN Zip: **3.5 Miles SE of Bedford-Northwest Quarter of Section 7**
MSOP Revision: **SPR 093-16653**
Plt ID: **093-00028**
Reviewer: **Michael S. Schaffer**
Date: **October 11, 2002**

Calculated lb/MMBtu No. 2 Fuel Oil Emission Factors

Pollutant	Vendor Guarantee Emission Rate (lb/hr)	Heat Input Capacity (MMBtu/hr)	Emission Factor (lb/MMBtu)
PM	12.00	384.05	0.03125
PM-10	12.00	384.05	0.03125
SO2*	N/A	384.05	0.10100
NOx	65.0	384.05	0.16925
VOC	6.00	384.05	0.01562
CO	21.0	384.05	0.05468

Methodology
Vender Guarantee Emission Rate in lb/hr / heat input capacity in MMBtu/hr = Emission Factor in lb/MMBtu
* lb MMBtu emission factor SO2 is based on AP-42

Worst Case No. 2 Fuel Oil Usage Determination

Pollutant	Limit for Turbines (tons/yr)	Conversion Factor (lbs/ton)	Emission Rate of Pollutant (lb/hr)	Source-wide Potential No.2 Fuel Oil Usage Rate (gal/hr)	Potential No. 2 Fuel Oil Usage Rate Limit For Each Pollutant (gal/yr)
PM	249.97	2000	12.00	2762.93	115108300
PM-10	249.97	2000	12.00	2762.93	115108300
SO2	249.92	2000	38.8	2762.93	35593384
NOx	**248.93**	**2000**	**65.0**	**2762.93**	**21162349**
VOC	249.87	2000	6.0	2762.93	230124503
CO	249.70	2000	21.0	2762.93	65705125

Methodology
(Limit for tubines in tons/yr x 2000 lbs/ton / Emission Rate of Pollutant) x Source-wide Potential No. 2 fuel oil usage rate in gal/hr =
Potential No. 2 fuel oil usage for each pollutant in gal/yr
Note than NOx is the worst case pollutant, thus, the source-wide No. 2 fuel oil usage limit will be based on 21,162,349 gal/yr

Appendix A: Emissions Calculations
No. 2 Fuel Oil Combustion Only
Turbines 1 - 6

Company Name: Hoosier Energy - Lawrence County Station
Address City IN Zip: 3.5 Miles SE of Bedford-Northwest Quarter of Section 7
MSOP Revision: SPR 093-16653
Plt ID: 093-00028
Reviewer: Michael S. Schaffer
Date: October 11, 2002

Equivalent Heat Input Capacity Based On No. 2 Fuel Oil Usage Limitation For The Six (6) Turbines

Source-wide No. 2 Fuel Oil Usage Limitation (gal/yr)	Heat Content of No. 2 Fuel Oil (Btu/gal)	Heat Content of No. 2 Fuel Oil (MMBtu/gal)	Equivalent Heat Input Capacity (MMBtu/yr)
21162349	139000	0.139000	**2941567**

Methodology
Heat content of No. 2 fuel oil in Btu/gal / 10^6 = Heat content of natural gas in MMBtu/cf
Source-wide No. 2 fuel oil usage limitation in gal/yr x Heat content of No. 2 fuel oil in MMBtu/gal = Equivalent heat input capacity MMBtu/yr

Annual Emissions For No. 2 Fuel Oil Usage Limitation Based On Worst Case Pollutant (NOx)

Pollutant	Equivalent Heat Input Capacity (MMBtu/yr)	Emission Factor (lb/MMBtu)	Conversion Factor (lbs/ton)	Limited Potential to Emit (tons/yr)
PM	2941567	0.03125	2000	**45.96**
PM-10	2941567	0.03125	2000	**45.96**
SO2	2941567	0.10100	2000	**148.55**
NOx	2941567	0.16925	2000	**248.93**
VOC	2941567	0.01562	2000	**22.98**
CO	2941567	0.05468	2000	**80.42**

Methodology
(Equivalent heat input capacity in MMBtu/yr x Emission factor in lb/MMBtu) / (2000 lbs/ton) = Limited potential to emit in tons/yr

Natural Gas and No. 2 Fuel Oil Equivalency Calculation

Potential No. 2 Fuel Oil Usage Rate Limit For Each Pollutant (gal/yr)	Potential Natural Gas Usage Rate Limit For Each Pollutant (mmcf/yr)	Number of Gallons Used to Determine No. 2 Fuel Oil Eqivalency	Natural Gas Usage Equivalent to 1000 gallons of No. 2 Fuel Oil (mmcf)
21162349	5324	1000	0.2516

Methodology
Number of Gallons Used to Determine No. 2 Fuel Oil Equivalency / No. 2 Fuel Oil Usage Rate Limit =
Natural Gas Usage equivalent to 1000 Gallons of No. 2 Fuel Oil in mmcf / Potential Natural Gas Usage Rate Limit For Each Pollutant (mmcf/yr)
1000 gallons / 21162349 gallons per year = 0.2516 mmcf / 5,324 mmcf per year

Appendix A: Emissions Calculations
Natural Gas Combustion Only
Turbines 1 - 6

Company Name: **Hoosier Energy - Lawrence County Station**
Address City IN Zip: **3.5 Miles SE of Bedford-Northwest Quarter of Section 7**
MSOP Revision: **SPR 093-16653**
Plt ID: **093-00028**
Reviewer: **Michael S. Schaffer**
Date: **October 11, 2002**

Emissions Limitations for Revision

Pollutant	PM (tons/yr)	PM-10 (tons/yr)	SO2 (tons/yr)	NOx (tons/yr)	VOC (tons/yr)	CO (tons/yr)
Limit	250	250	250	250	250	250
Fire Pump (Pump 1)	0.030	0.030	0.080	1.07	0.130	0.300
Limit For Turbines	249.97	249.97	249.92	248.93	249.87	249.70

For detailed fire pump emissions calculations see the Appendix A to the TSD of MSOP 093-14485-00028

Heat Output Capacity to Heat Input Capacity Conversion For Natural Gas

Nameplate Capacity of Each Turbine (kW)	Conversion Factor (Btu/kW-hr)	Heat Input Capacity of Each Turbine (Btu/hr)	Heat Input Capacity of Each Turbine (MMBtu/hr)
43771	8783	384440693.00	**384.44**

Methodology
Nameplate capacity in kilowatts (kw) x conversion factor in Btu/kW-hr = Heat input capacity in Btu
Heat input capacity in Btu/hr / 1,000,000 = Heat input capcity in MMBtu/hr

Potential Natural Gas Usage of The Six (6) Turbines

Heat Input Capacity (Btu/hr)	Heat Content of Natural Gas (Btu/cf)	Potential Natural Gas Usage Rate (cf/hr)	Potential Natural Gas Usage Rate (mmcf/hr)
384440693	946	406386	**0.406**

Methodology
Heat input capacity in Btu/hr / heat content of natural gas in Btu/cf = Natural gas usage rate in cf/hr
Natural gas usage rate in cf/hr / 1,000,000 = Natural gas usage rate in mmcf/hr

Appendix A: Emissions Calculations
Natural Gas Combustion Only
Turbines 1 - 6

Company Name: **Hoosier Energy - Lawrence County Station**
Address City IN Zip: **3.5 Miles SE of Bedford-Northwest Quarter of Section 7**
MSOP Revision: **SPR 093-16653**
Plt ID: **093-00028**
Reviewer: **Michael S. Schaffer**
Date: **October 11, 2002**

Calculated lb/MMBtu Natural Gas Emission Factors

Pollutant	Vendor Guarantee Emission Rate (lb/hr)	Heat Input Capacity (MMBtu/hr)	Emission Factor (lb/MMBtu)
PM	3.00	384.44	0.00780
PM-10	3.00	384.44	0.00780
SO2*	N/A	384.44	0.00060
NOx	42.5	384.44	0.11055
VOC	8.00	384.44	0.02081
CO	21.0	384.44	0.05462

Methodology
Vender Guarantee Emission Rate in lb/hr / heat input capacity in MMBtu/hr = Emission Factor in lb/MMBtu
* lb MMBtu emission factor SO2 is based on AP-42

Worst Case Natural Gas Usage Determination

Pollutant	Limit for Turbines (tons/yr)	Conversion Factor (lbs/ton)	Emission Rate of Pollutant Per Turbine (lb/hr)	Potential Natural Gas Usage Rate Per Turbine (mmcf/hr)	Potential Natural Gas Usage Rate Limit For Each Pollutant (mmcf/yr)
PM	249.97	2000	3.00	0.406	67723
PM-10	249.97	2000	3.00	0.406	67723
SO2	249.92	2000	0.230	0.406	883164
NOx	**248.93**	**2000**	**42.5**	**0.406**	**4760.5**
VOC	249.87	2000	8.00	0.406	25386
CO	249.70	2000	21.0	0.406	9664

Methodology
(Limit for tubines in tons/yr x 2000 lbs/ton / Emission Rate of Pollutant Per Turbine) x Potential Natural Gas Usage Rate Per Turbine in mmcf/hr =
Potential natural gas usage rate for each pollutant in mmcf/hr
Note than NOx is the worst case pollutant, thus, the source-wide natural gas usage limit will be based on 4,760.5 mmcf/yr

Appendix A: Emissions Calculations
Natural Gas Combustion Only
Turbines 1 - 6

Company Name: **Hoosier Energy - Lawrence County Station**
Address City IN Zip: **3.5 Miles SE of Bedford-Northwest Quarter of Section 7**
MSOP Revision: **SPR 093-16653**
Plt ID: **093-00028**
Reviewer: **Michael S. Schaffer**
Date: **October 11, 2002**

Equivalent Heat Input Capacity Based On Natural Gas Usage Limitation For The Six (6) Turbines

Source-wide Natural Gas Usage Limitation (mmcf/yr)	Source-wide Natural Gas Usage Limitation (cf/yr)	Heat Content of Natural Gas (Btu/cf)	Heat Content of Natural Gas (MMBtu/cf)	Equivalent Heat Input Capacity (MMBtu/yr)
4760.5	4760543301	946	0.000946	**4503474**

Methodology
Source-wide natural gas usage in mmcf/yr x 10^6 = Source-wide natural gas usage in cf/yr
Heat content of natural gas in Btu/cf / 10^6 = Heat content of natural gas in MMBtu/cf
Source-wide natural gas usage limitation in cf/yr x Heat content of natural gas in MMBtu/cf = Equivalent heat input capacity MMBtu/yr

Annual Emissions For Natural Gas Usage Limitation Based On Worst Case Pollutant (NOx)

Pollutant	Equivalent Heat Input Capacity (MMBtu/yr)	Emission Factor (lb/MMBtu)	Conversion Factor (lbs/ton)	Limited Potential to Emit (tons/yr)
PM	4503474	0.00780	2000	**17.57**
PM-10	4503474	0.00780	2000	**17.57**
SO2	4503474	0.00060	2000	**1.35**
NOx	4503474	0.11055	2000	**248.93**
VOC	4503474	0.02081	2000	**46.86**
CO	4503474	0.05462	2000	**123.00**

Methodology
(Equivalent heat input capacity in MMBtu/yr x Emission factor in lb/MMBtu) / (2000 lbs/ton) = Limited potential to emit in tons/yr

Appendix A: Emissions Calculations
No. 2 Fuel Oil Combustion Only
Turbines 1 - 6

Company Name: Hoosier Energy - Lawrence County Station
Address City IN Zip: 3.5 Miles SE of Bedford-Northwest Quarter of Section 7
MSOP Revision: SPR 093-16653
Plt ID: 093-00028
Reviewer: Michael S. Schaffer
Date: October 11, 2002

Emissions Limitations for Revision

Pollutant	PM (tons/yr)	PM-10 (tons/yr)	SO2 (tons/yr)	NOx (tons/yr)	VOC (tons/yr)	CO (tons/yr)
Limit	250	250	250	250	250	250
Fire Pump (Pump 1)	0.030	0.030	0.080	1.07	0.130	0.300
Limit For Turbines	249.97	249.97	249.92	248.93	249.87	249.70

For detailed fire pump emissions calculations see the Appendix A to the TSD of MSOP 093-14485-00028

Heat Output Capacity to Heat Input Capacity Conversion For No. 2 Fuel Oil

Nameplate Capacity of Each Turbine (kW)	Conversion Factor (Btu/kW-hr)	Heat Input Capacity of Each Turbine (Btu/hr)	Heat Input Capacity of Each Turbine (MMBtu/hr)
42872	8958	384047376	**384.05**

Methodology
Nameplate capacity in kilowatts (kw) x conversion factor in Btu/kW-hr = heat input capacity in Btu
Heat input capacity in Btu/hr / 1,000,000 = heat input capcity in MMBtu/hr

Potential No. 2 Fuel Oil Usage in the Six (6) Turbines

Heat Input Capacity (Btu/hr)	Heat Content of No. 2 Fuel Oil (Btu/gal)	Potential No. 2 Fuel Oil Usage Rate (gal/hr)	Potential No. 2 Fuel Oil Usage Rate (kgal/hr)
384047376	139000	2763	**2.763**

Methodology
Heat input capacity in Btu/hr / heat content of No. 2 fuel oil in Btu/gal = Potential No. 2 fuel oil usage rate in gal/hr
No.2 fuel oil usage rate in gal/hr / 1,000,000 = No. 2 fuel oil usage rate in kgal/hr

Appendix A: Emissions Calculations
No. 2 Fuel Oil Combustion Only
Turbines 1 - 6

Company Name: **Hoosier Energy - Lawrence County Station**
Address City IN Zip: **3.5 Miles SE of Bedford-Northwest Quarter of Section 7**
MSOP Revision: **SPR 093-16653**
Plt ID: **093-00028**
Reviewer: **Michael S. Schaffer**
Date: **October 11, 2002**

Calculated lb/MMBtu No. 2 Fuel Oil Emission Factors

Pollutant	Vendor Guarantee Emission Rate (lb/hr)	Heat Input Capacity (MMBtu/hr)	Emission Factor (lb/MMBtu)
PM	12.00	384.05	0.03125
PM-10	12.00	384.05	0.03125
SO2*	N/A	384.05	0.10100
NOx	72.7	384.05	0.18930
VOC	6.00	384.05	0.01562
CO	21.0	384.05	0.05468

Methodology
Vender Guarantee Emission Rate in lb/hr / heat input capacity in MMBtu/hr = Emission Factor in lb/MMBtu
* lb MMBtu emission factor SO2 is based on AP-42

Worst Case No. 2 Fuel Oil Usage Determination

Pollutant	Limit for Turbines (tons/yr)	Conversion Factor (lbs/ton)	Emission Rate of Pollutant Per Turbine (lb/hr)	Potential No.2 Fuel Oil Usage Rate Per Turbine (gal/hr)	Potential No. 2 Fuel Oil Usage Rate Limit For Each Pollutant (gal/yr)
PM	249.97	2000	12.00	2762.93	115108300
PM-10	249.97	2000	12.00	2762.93	115108300
SO2	249.92	2000	38.8	2762.93	35593384
NOx	**248.93**	**2000**	**72.7**	**2762.93**	**18920945**
VOC	249.87	2000	6.0	2762.93	230124503
CO	249.70	2000	21.0	2762.93	65705125

Methodology
(Limit for tubines in tons/yr x 2000 lbs/ton / Emission Rate of Pollutant Per Turbine) x Potential No. 2 Fuel Oil Usage Rate Per Turbine in gal/hr =
Potential No. 2 fuel oil usage for each pollutant in gal/yr
Note than NOx is the worst case pollutant, thus, the source-wide No. 2 fuel oil usage limit will be based on 18,920,945 gal/yr

Appendix A: Emissions Calculations
No. 2 Fuel Oil Combustion Only
Turbines 1 - 6

Company Name: Hoosier Energy - Lawrence County Station
Address City IN Zip: 3.5 Miles SE of Bedford-Northwest Quarter of Section 7
MSOP Revision: SPR 093-16653
Plt ID: 093-00028
Reviewer: Michael S. Schaffer
Date: October 11, 2002

Equivalent Heat Input Capacity Based On No. 2 Fuel Oil Usage Limitation For The Six (6) Turbines

Source-wide No. 2 Fuel Oil Usage Limitation (gal/yr)	Heat Content of No. 2 Fuel Oil (Btu/gal)	Heat Content of No. 2 Fuel Oil (MMBtu/gal)	Equivalent Heat Input Capacity (MMBtu/yr)
18920945	139000	0.139000	**2630011**

Methodology
Heat content of No. 2 fuel oil in Btu/gal / 10^6 = Heat content of natural gas in MMBtu/cf
Source-wide No. 2 fuel oil usage limitation in gal/yr x Heat content of No. 2 fuel oil in MMBtu/gal = Equivalent heat input capacity MMBtu/yr

Annual Emissions For No. 2 Fuel Oil Usage Limitation Based On Worst Case Pollutant (NOx)

Pollutant	Equivalent Heat Input Capacity (MMBtu/yr)	Emission Factor (lb/MMBtu)	Conversion Factor (lbs/ton)	Limited Potential to Emit (tons/yr)
PM	2630011	0.03125	2000	**41.09**
PM-10	2630011	0.03125	2000	**41.09**
SO2	2630011	0.10100	2000	**132.82**
NOx	2630011	0.18930	2000	**248.93**
VOC	2630011	0.01562	2000	**20.54**
CO	2630011	0.05468	2000	**71.91**

Methodology
(Equivalent heat input capacity in MMBtu/yr x Emission factor in lb/MMBtu) / (2000 lbs/ton) = Limited potential to emit in tons/yr

Natural Gas and No. 2 Fuel Oil Equivalency Calculation

Potential No. 2 Fuel Oil Usage Rate Limit For Each Pollutant (gal/yr)	Potential Natural Gas Usage Rate Limit For Each Pollutant (mmcf/yr)	Number of Gallons Used to Determine No. 2 Fuel Oil Eqivalency	Natural Gas Usage Equivalent to 1000 gallons of No. 2 Fuel Oil (mmcf)
18920945	4760.5	1000	0.2516

Methodology
Number of Gallons Used to Determine No. 2 Fuel Oil Equivalency / No. 2 Fuel Oil Usage Rate Limit =
Natural Gas Usage equivalent to 1000 Gallons of No. 2 Fuel Oil in mmcf / Potential Natural Gas Usage Rate Limit For Each Pollutant (mmcf/yr)
1000 gallons / 18,920,945 gallons per year = 0.2516 mmcf / 4,760.5 mmcf per year